THIRD QUARTER REPORT

Canadian Natural

NINE MONTHS ENDED SEPTEMBER 30, 2009

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2009 THIRD QUARTER RESULTS AND 2010 BUDGET

Canadian Natural's Chairman, Allan Markin, stated, "The third quarter was strong for Canadian Natural as we met all of our production targets, with the exception of Horizon, which encountered certain unexpected challenges during the ramp-up of its production levels. The challenges at Horizon are manageable and our teams are doing a great job in identifying and mitigating these issues. We continue to execute our defined growth plan in 2010, with all areas providing positive free cash flow in the range of $2.6 to $3.0 billion while still delivering 7% production growth."

Canadian Natural's Vice-Chairman, John Langille, continued, "Our balance sheet continued to strengthen during the quarter as we completed the retirement of the $2.3 billion non-revolving syndicated acquisition credit facility, with all payments made from internally generated cash flow. This brings our debt to book capitalization to 36%, essentially at the low end of our targeted range. Our debt to EBITDA is 1.6x, which is below our targeted range. Crude oil prices and the heavy oil differential remained favorable, and along with our hedging program, helped to mitigate the impact of weak natural gas prices. Looking to 2010, overall budget capital spending will be increased over 2009 levels but remains well within targeted cash flow, resulting in even further balance sheet strength."

Steve Laut, President and Chief Operating Officer of Canadian Natural concluded, "Our 2010 budget represents a prudent yet flexible approach to developing our world class assets. For 2010, budgeted capital spending is targeted to increase 26% over 2009 with over 80% of our capital allocated to the development of our crude oil assets. We will continue our disciplined, step-wise development of our vast heavy crude oil properties and start to unlock the significant EOR potential of our light crude oil properties in Canada. We will complete the Olowi development in West Africa and resume platform drilling in the North Sea. Spending at Horizon for the coming year is focused on Tranche 2 of Phases 2/3 and features a significant expenditure on developing a detailed cost estimate for future expansions. This capital budget provides us with the flexibility to react to fluctuations within the business environment. If economic conditions improve significantly during the coming year or other opportunities arise, we have the assets and the ability to focus capital on the projects that provide the greatest value and highest returns."

QUARTERLY HIGHLIGHTS

($ millions, except as noted)	Three Months Ended Sep 30 2009	Jun 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Net earnings	**$ 658**	$ 162	$ 2,835	**$ 1,125**	$ 3,215
per common share, basic and diluted	**$ 1.21**	$ 0.30	$ 5.25	**$ 2.07**	$ 5.95
Adjusted net earnings from operations (1)	**$ 658**	$ 637	$ 963	**$ 2,022**	$ 2,795
per common share, basic and diluted	**$ 1.21**	$ 1.18	$ 1.78	**$ 3.73**	$ 5.17
Cash flow from operations (2)	**$ 1,506**	$ 1,365	$ 1,815	**$ 4,387**	$ 5,399
per common share, basic and diluted	**$ 2.78**	$ 2.52	$ 3.36	**$ 8.10**	$ 9.99
Capital expenditures, net of dispositions	**$ 574**	$ 473	$ 1,744	**$ 2,303**	$ 5,624
Daily production, before royalties					
Natural gas (mmcf/d)	**1,293**	1,352	1,490	**1,338**	1,518
Crude oil and NGLs (bbl/d)	**359,269**	365,672	306,970	**351,760**	317,715
Equivalent production (boe/d)	**574,755**	590,984	555,356	**574,688**	570,704

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

- Total crude oil and NGLs production for Q3/09 was 359,269 bbl/d, an increase of 17% from Q3/08 volumes. Higher volumes in Q3/09 reflect production increases from Horizon Oil Sands Mining and Upgrading ("Horizon"), Baobab and Olowi offset by the temporary curtailment of steaming/production at Primrose East and planned maintenance in the North Sea.
- Natural gas production for Q3/09 averaged 1,293 mmcf/d, down 13% from Q3/08, as expected. The decrease in volumes for Q3/09 from previous quarters reflects the continuing reallocation of capital towards higher return crude oil projects.
- Quarterly cash flow from operations was $1,506 million, an increase of 10% from the previous quarter and a decrease of 17% from Q3/08. The increase from Q2/09 reflects higher crude oil price realizations partially offset by lower natural gas price realizations and lower natural gas sales volumes. The decrease from Q3/08 reflects lower crude oil and natural gas price realizations, partially offset by higher crude oil production.
- Quarterly net earnings and adjusted net earnings for Q3/09 was $658 million.
- Horizon production averaged 66,907 bbl/d of Synthetic Crude Oil ("SCO") for Q3/09 up from 59,599 bbl/d of SCO average production in Q2/09. The volumes were less than targeted due to a number of unforeseen production challenges that arose mid-way through the third quarter.
- Declared a quarterly cash dividend on common shares of $0.105 per common share payable January 1, 2010.

OPERATIONS REVIEW

Activity by core region

	Net undeveloped land as at Sep 30, 2009 (thousands of net acres)	Drilling activity nine months ended Sep 30, 2009 (net wells) (1)
North America conventional		
Northeast British Columbia	**2,068**	**17.0**
Northwest Alberta	**1,184**	**39.5**
Northern Plains	**5,940**	**407.3**
Southern Plains	**813**	**11.4**
Southeast Saskatchewan	**138**	**13.4**
Thermal In-situ Oil Sands	**487**	**270.0**
	10,630	**758.6**
Oil Sands Mining and Upgrading	**115**	**42.0**
North Sea	**180**	**1.2**
Offshore West Africa	**188**	**6.1**
	11,113	**807.9**

(1) Drilling activity includes stratigraphic test and service wells.

Drilling activity (number of wells)

	Nine Months Ended Sep 30			
	2009		2008	
	Gross	**Net**	Gross	Net
Crude oil	**476**	**449**	529	500
Natural gas	**107**	**81**	304	228
Dry	**32**	**29**	32	28
Subtotal	**615**	**559**	865	756
Stratigraphic test / service wells	**249**	**249**	36	34
Total	**864**	**808**	901	790
Success rate (excluding stratigraphic test / service wells)		**95%**		96%

North America Conventional

North America natural gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Natural gas production (mmcf/d)	**1,264**	1,322	1,467	**1,311**	1,494
Net wells targeting natural gas	**17**	-	62	**89**	237
Net successful wells drilled	**17**	-	62	**81**	228
Success rate	**100%**	-	100%	**91%**	96%

- Q3/09 North America natural gas production, as expected, decreased 14% from Q3/08 and 4% from Q2/09, reflecting natural declines in base production and the Company's strategic decision to reduce spending on natural gas drilling due to stronger economics in crude oil projects.
- Canadian Natural targeted 17 net natural gas wells in Q3/09, including 2 wells in Northeast British Columbia, 8 wells in the Northern Plains region, 6 wells in Northwest Alberta, and 1 well in the Southern Plains region.
- Planned drilling activity for Q4/09 includes 25 net natural gas wells. In light of current natural gas economics, including pricing and the impact of Alberta's royalty regime, the Company continues to focus on land expiries, competitive drainage issues and advancing development of key resource projects, such as those identified in the Montney formation of British Columbia.

North America crude oil and NGLs

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs production (bbl/d)	**223,307**	232,139	239,973	**236,315**	244,832
Net wells targeting crude oil	**270**	97	244	**464**	514
Net successful wells drilled	**260**	93	233	**443**	496
Success rate	**96%**	96%	95%	**95%**	96%

- Q3/09 North America crude oil and NGLs production decreased 7% from Q3/08 and 4% from Q2/09 levels. The majority of the decline in production volumes was in thermal crude oil reflecting Primrose North and South normal steam/production cycles, and the temporary curtailment of the thermal steam/production cycle at Primrose East.
- As previously disclosed, in Q1/09 after initial steaming at Primrose East, Canadian Natural discovered oil seepage at surface on one of the new multi well pads. A significant amount of investigative work was completed and the Company formalized and received approval for a plan to begin diagnostic steaming which commenced in August of this year. The Company continues to proactively work with the regulators to identify and resolve the issue and facilitate the prudent return of Primrose East to normal operations.
- Canadian Natural is continuing its proposed third phase of its defined thermal growth plan with development of the Kirby In-Situ Oil Sands Project. Kirby is located approximately 85 km northeast of Lac La Biche in the Regional Municipality of Wood Buffalo and has a targeted capacity of 45,000 bbl/d. The Company has filed its formal regulatory application documents for this project and is awaiting regulatory approval. Preliminary engineering is expected to commence in Q4/09. Upon completion of the engineering, Canadian Natural targets sanctioning of the project in late 2010.
- The development of new pads and conversion to tertiary recovery at Pelican Lake continued as expected throughout Q3/09. In Q3/09, the Company drilled 19 horizontal wells and plans an additional 19 horizontal wells throughout the remainder of 2009. Pelican Lake production averaged approximately 37,000 bbl/d for Q3/09.
- During Q3/09, drilling activity targeted 270 net crude oil wells including 217 wells targeting heavy crude oil, 19 wells targeting Pelican Lake crude oil, 24 wells targeting thermal crude oil and 10 wells targeting light crude oil.
- Planned drilling activity for Q4/09 includes 223 net crude oil wells, excluding stratigraphic test and service wells.

International

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil production (bbl/d)					
North Sea	**34,034**	40,362	42,760	**38,891**	46,041
Offshore West Africa	**35,021**	33,572	24,237	**33,025**	26,842
Natural gas production (mmcf/d)					
North Sea	**8**	10	9	**9**	10
Offshore West Africa	**21**	20	14	**18**	14
Net wells drilled	**2.2**	1.0	0.6	**6.4**	4.4
Net successful wells drilled	**1.9**	1.0	0.6	**6.1**	3.6
Success rate	**86%**	100%	100%	**95%**	82%

North Sea

- As expected, production was lower in Q3/09 compared to Q2/09 and Q3/08 due to planned maintenance shutdowns at all three of the Ninian platforms and at Tiffany. During the quarter, the Company continued to focus on lowering costs, high grading inventory and identifying infill drilling opportunities.

Offshore West Africa

- Offshore West Africa's crude oil production for Q3/09 was 35,021 bbl/d, an increase of 4% from Q2/09 and an increase of 44% over Q3/08, reflecting strong performance at Baobab and Espoir, and the commencement of operations at Olowi.
- During Q3/09, two new wells were tied in at the Olowi Field. Production to date from the first platform is below expectations. The Company is currently reviewing drilling results and production data to determine the root cause of well performance issues in order to develop appropriate remediation strategies and determine the impact on future production from the field and the impact on recoverable reserves. While the Company continues drilling the next scheduled platform, it is also reviewing ongoing/future development activities, which may result in changes to the scope of the overall plan.
- Progress on the Facility Upgrade Project at Espoir to increase processing capacity of the Floating Production Storage and Offtake Vessel ("FPSO") has reverted to the original schedule to accommodate effective utilization of the installation vessel at Olowi.

Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Synthetic Crude Oil Production (bbl/d)	**66,907**	59,599	-	**43,529**	-

- Horizon production in Q3/09 averaged 66,907 bbl/d of SCO. Production was lower than guidance due to a number of challenges arising mid-way through the third quarter after the successful commencement of operations in the second quarter. The challenges related primarily to:
  1. Premature equipment failures in the Ore Preparation Plant, Primary Upgrading, the Naphtha Recovery Unit and the Sulphur Plant.
  2. Ore processing challenges arising in September resulting from a higher percentage of clays in the second mine bench and the lack of available blending materials from other mine benches associated with early mine operations.

- Canadian Natural believes it has largely resolved the matters associated with equipment and plant reliability. However, the Company remains cautious as it enters the first full winter of operations due to the challenges of operating in the northern Alberta environment. The processing issue from the higher percentage of clays will continue until additional mine benches are completed facilitating better blending of consistent ore qualities. This activity is currently underway with a focus on the third mine bench. The Company anticipates that it may take until the end of the second quarter of 2010 to fully resolve the ore blending issue.
- Engineering and procurement is underway for Tranche 2 of the Phase 2/3 expansion with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs pricing					
WTI [1] benchmark price (US$/bbl)	**$ 68.29**	$ 59.61	$ 118.13	**$ 57.13**	$ 113.38
Western Canadian Select blend differential from WTI (%)	**15%**	13%	15%	**15%**	18%
SCO price (US$/bbl)	**$ 67.20**	$ 58.42	$ 121.96	**$ 56.95**	$ 117.20
Corporate average pricing before risk management (C$/bbl)	**$ 62.90**	$ 59.56	$ 102.30	**$ 54.17**	$ 94.72
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.87**	$ 3.46	$ 8.78	**$ 3.88**	$ 8.16
Corporate average pricing before risk management (C$/mcf)	**$ 3.80**	$ 4.11	$ 8.82	**$ 4.46**	$ 8.83

(1) Refers to West Texas Intermediate (WTI) crude oil barrel priced at Cushing, Oklahoma.

- In Q3/09, the Western Canadian Select ("WCS") heavy crude oil differential as a percent of WTI was 15% compared to 13% in Q2/09. Heavy crude oil differentials remained narrow in Q3/09 due to stronger demand from the US refineries for heavy crude oil. The US refineries are experiencing weak refinery margins and this tends to increase the demand for the lowest cost crude oil, which is generally heavier crude oil.
- During Q3/09, the Company allocated approximately 124,000 bbl/d of its heavy crude oil streams to the WCS blend, optimizing the pricing for heavy crude oil. WCS is in the early stages of being recognized as a heavy crude oil benchmark for North America.
- The marketing strategy for Horizon SCO remains flexible. There is an active market for Horizon SCO and it has been favorably accepted by refiners.
- Natural gas pricing for Q3/09 continued to weaken compared to prior periods primarily due to supply/demand imbalances. North America natural gas inventory levels remained high during the third quarter due to an oversupply from US producers and lower industrial consumption.

FINANCIAL REVIEW

- The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its commodity hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing credit facilities and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy. A brief summary of the Company's strengths are:
  - A diverse asset base geographically and by product - produced approximately 575,000 boe/d in Q3/09, comprised of approximately 38% natural gas and 62% crude oil - with approximately 93% of production located in G8 countries.

- Financial stability and liquidity - cash flow from operations of $1,506 million for Q3/09, with available unused bank lines of $1,261 million at September 30, 2009.
- Reduced volatility of commodity prices - a proactive commodity hedging program to reduce the downside risk of volatility in commodity prices supporting cash flow for its capital expenditure program.
- A strengthening balance sheet with debt to book capitalization of 36% which is at the low end of the Company's targeted range, and debt to EBITDA of 1.6 times, below the targeted range.

▪ In Q3/09 the $2.3 billion non-revolving syndicated acquisition credit facility was retired prior to its maturity in October 2009.

▪ Declared a quarterly cash dividend on common shares of C$0.105 per common share, payable January 1, 2010.

OUTLOOK

▪ The Company forecasts 2009 production levels before royalties to average between 1,305 and 1,314 mmcf/d of natural gas and between 352,000 and 363,000 bbl/d of crude oil and NGLs. Q4/09 production guidance before royalties is forecast to average between 1,213 and 1,243 mmcf/d of natural gas and between 359,000 and 390,000 bbl/d of crude oil and NGLs. Detailed guidance on production levels and capital allocation can be found on the Company's website at http://www.cnrl.com/investor_info/corporate_guidance/.

HIGHLIGHTS OF THE 2010 BUDGET

▪ Equivalent production target of 586,000 to 643,000 boe/d before royalties, representing a midpoint increase of 7% from the midpoint of 2009 forecasted annual average production guidance. Exit to exit production is targeted to increase 17% in 2010.

▪ Crude oil and NGLs production target of 400,000 to 445,000 bbl/d before royalties, representing a midpoint increase of 18% from the midpoint of 2009 forecasted annual guidance. The increase reflects the ramp up of operations at the Horizon Oil Sands, the drilling of additional pads in Primrose North and Pelican Lake, and target ramp-up at Primrose East, offset by reduced activity in the North Sea.

▪ Natural gas production target of 1,117 to 1,185 mmcf/d before royalties, representing a midpoint decrease of 12% from the midpoint of 2009 forecasted annual guidance. The decrease reflects an 18% reduction in drilling activity levels year over year, largely as a result of the economic impacts of low natural gas prices and increased royalties in Alberta.

▪ Based upon targeted production and forward strip pricing on October 27, 2009 (US$82.00/bbl, Western Canadian Select heavy oil differential of 22%, NYMEX natural gas price of US$6.00/mmbtu and exchange rate of C$1.00 = US$0.94), cash flow from operations is targeted to be between $6.5 billion and $6.9 billion ($12.00 - $12.70 per common share).

▪ Capital spending in 2010 is budgeted at $3.9 billion, a 26% increase over 2009.

▪ Free cash flow (cash flow after capital), is targeted between $2.6 billion and $3.0 billion based on October 27, 2009 forward strip pricing. Free cash flow will initially be used to reduce debt facilities.

▪ Canadian conventional crude oil and natural gas capital expenditures of $2.6 billion in 2010, representing a 50% increase in capital spending from 2009 levels. The increase is due to a record primary heavy crude oil drilling program, a 94% increase in capital allocation to expand polymer flooding at Pelican Lake, increased focus on the Enhanced Oil Recovery program, and the progression of our thermal crude oil development plan.

▪ Canadian Natural is progressing with initial development stages of the Septimus/Montney natural gas play in British Columbia with 13 wells planned for 2010.

▪ International conventional crude oil and natural gas capital expenditures are budgeted to be $463 million, a decrease of 36% from 2009. Planned activity includes completing the start up of one drill string in the North Sea and completion of the Olowi development in Offshore Gabon.

- Canadian Natural has significant capital flexibility in the 2010 capital program allowing the Company to quickly adapt our capital spending profile to commodity price environment.

- Included in the 2010 budget is approximately $479 million of capital for Horizon Phase 2/3 Tranche 2 expenditures targeted to increase reliability of the plant while also affording some de-bottlenecking opportunities. Additionally, Canadian Natural has budgeted approximately $95 million for completion of engineering work to provide a higher degree of cost certainty for future expansion.

- Continued strong balance sheet management which provides financial flexibility for operating plans.

Capital and Production Guidance

Canadian Natural continues its strategy of maintaining a large portfolio of varied projects. This enables the Company to provide consistent growth in production and high shareholder returns over an extended period of time. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of project returns, product pricing expectations, and balance project risks and time horizons. Canadian Natural maintains a high ownership level and operatorship in its properties and can therefore control the nature, timing and extent of expenditures in each of its project areas.

The budgeted capital expenditures in 2009 and 2010 are as follows:

($ millions)	2009 Forecast	**2010 Budget**
Conventional crude oil and natural gas		
North America natural gas	$ 495	**$ 674**
North America crude oil and NGLs	1,220	**1,900**
North Sea	170	**199**
Offshore West Africa	550	**264**
Property acquisitions, dispositions and midstream	85	**100**
	2,520	**3,137**
Horizon Oil Sands Mining and Upgrading		
Phase 1 – Construction	$ 90	**$ -**
Phase 1 – Operating inventory, capital inventory and commissioning	200	**-**
Phase 2/3 – Tranche 2	135	**479**
Phase 2/3 – Engineering	-	**95**
Sustaining capital	100	**164**
Capitalized interest and other costs	75	**47**
	600	**785**
	$ 3,120	**$ 3,922**

The above capital expenditure budget incorporates the following levels of drilling activity:

Drilling activity (number of net wells)	2009 Forecast	**2010 Budget**
Targeting natural gas	114	**93**
Targeting crude oil	695	**966**
Stratigraphic test / service wells – conventional	220	**227**
Stratigraphic test wells – mining	107	**166**
Total	1,136	**1,452**

The production guidance for 2010 is as follows:

Daily production volumes, before royalties	**2010 Budget**
Natural gas (mmcf/d)	
North America	**1,080 – 1,140**
North Sea	**17 – 21**
Offshore West Africa	**20 – 24**
	1,117 – 1,185
Crude oil and NGLs (mbbl/d)	
North America – Conventional	**250 – 270**
North America – Oil Sands Mining and Upgrading	**90 – 105**
North Sea	**31 – 36**
Offshore West Africa	**29 – 34**
	400 – 445

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to Horizon Oil Sands Mining and Upgrading operations, Primrose East, Pelican Lake, Gabon (Offshore West Africa), and the Kirby Thermal Oil Sands Project also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year if necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected difficulties in mining, extracting or upgrading the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, bitumen, natural gas and liquids not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

Management's Discussion and Analysis of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the nine months ended September 30, 2009 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2008.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("GAAP"). This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, and cash production costs. These financial measures are not defined by GAAP and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with GAAP, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with GAAP, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead.

Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion refers primarily to the Company's financial results for the nine and three months ended September 30, 2009 in relation to the comparable periods in 2008 and the second quarter of 2009. The accompanying tables form an integral part of this MD&A. This MD&A is dated November 3, 2009. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2008, is available on SEDAR at www.sedar.com.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Revenue, before royalties	**$ 2,823**	$ 2,750	$ 4,583	**$ 7,759**	$ 13,662
Net earnings	**$ 658**	$ 162	$ 2,835	**$ 1,125**	$ 3,215
Per common share – basic and diluted	**$ 1.21**	$ 0.30	$ 5.25	**$ 2.07**	$ 5.95
Adjusted net earnings from operations (1)	**$ 658**	$ 637	$ 963	**$ 2,022**	$ 2,795
Per common share – basic and diluted	**$ 1.21**	$ 1.18	$ 1.78	**$ 3.73**	$ 5.17
Cash flow from operations (2)	**$ 1,506**	$ 1,365	$ 1,815	**$ 4,387**	$ 5,399
Per common share – basic and diluted	**$ 2.78**	$ 2.52	$ 3.36	**$ 8.10**	$ 9.99
Capital expenditures, net of dispositions	**$ 574**	$ 473	$ 1,744	**$ 2,303**	$ 5,624

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presented below lists the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presented below lists certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

	Three Months Ended			*Nine Months Ended*	
($ millions)	***Sep 30 2009***	*Jun 30 2009*	*Sep 30 2008*	***Sep 30 2009***	*Sep 30 2008*
Net earnings as reported	***$ 658***	*$ 162*	*$ 2,835*	***$ 1,125***	*$ 3,215*
Stock-based compensation expense (recovery), net of tax (a)	***126***	*67*	*(221)*	***196***	*107*
Unrealized risk management loss (gain), net of tax (b)	***217***	*676*	*(1,750)*	***1,213***	*(677)*
Unrealized foreign exchange (gain) loss, net of tax (c)	***(343)***	*(268)*	*99*	***(493)***	*191*
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	**–**	*–*	*–*	***(19)***	*(41)*
Adjusted net earnings from operations	***$ 658***	*$ 637*	*$ 963*	***$ 2,022***	*$ 2,795*

(a) The Company's employee stock option plan provides for a cash payment option. Accordingly, the intrinsic value of the outstanding vested options is recorded as a liability on the Company's balance sheet and periodic changes in the intrinsic value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(c) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, offset by the impact of cross currency swaps, and are recognized in net earnings.

(d) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted or enacted. Income tax rate changes in the first quarter of 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America. Income tax rate changes in the first quarter of 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa.

Cash Flow from Operations

($ millions)	**Sep 30 2009** (Three Months Ended)	*Jun 30 2009* (Three Months Ended)	*Sep 30 2008* (Three Months Ended)	**Sep 30 2009** (Nine Months Ended)	*Sep 30 2008* (Nine Months Ended)
Net earnings	***$ 658***	*$ 162*	*$ 2,835*	***$ 1,125***	*$ 3,215*
Non-cash items:					
Depletion, depreciation and amortization	***673***	*664*	*659*	***1,983***	*2,017*
Asset retirement obligation accretion	***24***	*24*	*18*	***67***	*52*
Stock-based compensation expense (recovery)	***172***	*92*	*(308)*	***268***	*151*
Unrealized risk management loss (gain)	***274***	*946*	*(2,506)*	***1,683***	*(983)*
Unrealized foreign exchange (gain) loss	***(391)***	*(320)*	*113*	***(573)***	*219*
Deferred petroleum revenue tax (recovery) expense	***13***	*(2)*	*(7)*	***8***	*(62)*
Future income tax expense (recovery)	***83***	*(201)*	*1,011*	***(174)***	*790*
Cash flow from operations	***$ 1,506***	*$ 1,365*	*$ 1,815*	***$ 4,387***	*$ 5,399*

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net earnings for the nine months ended September 30, 2009 were $1,125 million compared to $3,215 million for the nine months ended September 30, 2008. Net earnings for the nine months ended September 30, 2009 included net unrealized after-tax expenses of $897 million related to the effects of risk management activities, fluctuations in foreign exchange rates, fluctuations in stock-based compensation, and the impact of statutory tax rate changes on future income tax liabilities, compared to net unrealized after-tax income of $420 million for the nine months ended September 30, 2008. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2009 were $2,022 million compared to $2,795 million for the nine months ended September 30, 2008. The decrease in adjusted net earnings from the nine months ended September 30, 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expenses, higher interest expense, and realized foreign exchange losses, partially offset by the impact of higher crude oil sales volumes related to the commencement of operations of Horizon Oil Sands (“Horizon”), realized risk management gains, lower depletion, depreciation and amortization expense, lower royalty expense, and the impact of the weaker Canadian dollar relative to the US dollar.

Net earnings for the third quarter of 2009 were $658 million compared to net earnings of $2,835 million for the third quarter of 2008 and net earnings of $162 million for the prior quarter. Net earnings for the third quarter of 2008 included net unrealized after-tax income of $1,872 million related to the effects of risk management activities, fluctuations in foreign exchange rates, and fluctuations in stock-based compensation, compared to net unrealized after-tax expenses of $475 million for the second quarter of 2009. Adjusted net earnings from operations for the third quarter of 2009 were $658 million compared to $963 million for the third quarter of 2008 and $637 million for the prior quarter. The decrease in adjusted net earnings from the third quarter of 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, and higher interest expense, partially offset by the impact of higher crude oil sales volumes related to the commencement of operations of Horizon, higher realized risk management gains, lower royalty expense, and the impact of the weaker Canadian dollar relative to the US dollar. The increase in adjusted net earnings from the prior quarter was primarily due to the impact of higher crude oil sales volumes related to Horizon, higher realized crude oil pricing, and realized foreign exchange gains, partially offset by the impact of lower natural gas sales volumes, lower realized risk management gains, higher royalty and production expenses, and the impact of the stronger Canadian dollar relative to the US dollar.

The impacts of unrealized risk management activities, stock-based compensation, and changes in foreign exchange rates are expected to continue to contribute to significant quarterly volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for the nine months ended September 30, 2009 was $4,387 million compared to $5,399 million for the nine months ended September 30, 2008. Cash flow from operations for the third quarter of 2009 was $1,506 million compared to $1,815 million for the third quarter of 2008 and $1,365 million for the prior quarter. The decrease in cash flow from operations from the comparable periods in 2008 was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, higher interest expense, and the impact of realized foreign exchange, partially offset by the impact of higher crude oil sales volumes related to the commencement of operations of Horizon, realized risk management gains, lower royalty expense, lower current income tax and current Production Revenue Tax (“PRT”) expense, and the impact of the weaker Canadian dollar relative to the US dollar. The increase in cash flow from operations from the prior quarter was primarily due to the impact of higher crude oil sales volumes related to Horizon, higher realized crude oil pricing, lower current PRT, and the impact of realized foreign exchange gains, partially offset by the impact of lower natural gas sales volumes, lower realized natural gas pricing, lower realized risk management gains, higher royalty and production expense, and the impact of the stronger Canadian dollar relative to the US dollar.

During 2009, the Company achieved first production of synthetic crude oil ("SCO") at Horizon in connection with the commencement of operations. The Company continues to focus on stabilizing and ramping up production as the plant is fine-tuned with a focus on safety, reliability, and cost control. The results of operations for Horizon are included in the "Oil Sands Mining and Upgrading" segment.

Total production before royalties for the nine months ended September 30, 2009 increased 1% to 574,688 boe/d from 570,704 boe/d for the nine months ended September 30, 2008. Total production before royalties for the third quarter of 2009 increased 3% to 574,755 boe/d from 555,356 boe/d for the third quarter of 2008 and decreased 3% from 590,984 boe/d for the prior quarter. Total production for the third quarter of 2009 was at the low end of the Company's previously issued guidance due to lower than anticipated SCO production at Horizon.

For a discussion of the impact of current worldwide financial and economic events, please refer to the "Liquidity and Capital Resources" section of this MD&A.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)		**Sep 30 2009**		Jun 30 2009		Mar 31 2009		Dec 31 2008
Revenue, before royalties	**$**	**2,823**	$	2,750	$	2,186	$	2,511
Net earnings	**$**	**658**	$	162	$	305	$	1,770
Net earnings per common share								
– Basic and diluted	**$**	**1.21**	$	0.30	$	0.56	$	3.27

($ millions, except per common share amounts)		Sep 30 2008		Jun 30 2008		Mar 31 2008		Dec 31 2007
Revenue, before royalties	$	4,583	$	5,112	$	3,967	$	3,200
Net earnings (loss)	$	2,835	$	(347)	$	727	$	798
Net earnings (loss) per common share								
– Basic and diluted	$	5.25	$	(0.65)	$	1.35	$	1.48

Volatility in quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – The impact of fluctuating demand and geopolitical uncertainties on worldwide benchmark pricing, and the fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.
- **Natural gas pricing** – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement of operations of Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa and the impact of the shut in, and subsequent restoration, of some of the production in the Baobab Field.

- **Natural gas sales volumes** – Production declines due to the Company's strategic decision to reduce natural gas drilling activity in North America due to the allocation of capital to higher return crude oil projects, as well as natural decline rates.
- **Production expense** – Fluctuations primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, and the commencement of operations of Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, and the commencement of operations of Horizon.
- **Stock-based compensation** – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price over the eight most recently completed quarters.
- **Risk management** – Fluctuations due to the recognition of realized and unrealized gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Similarly, unrealized foreign exchange gains and losses were recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.
- **Changes in income tax expense (recovery)** – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
WTI benchmark price (US$/bbl)	**$ 68.29**	$ 59.61	$ 118.13	**$ 57.13**	$ 113.38
Dated Brent benchmark price (US$/bbl)	**$ 68.28**	$ 58.78	$ 114.96	**$ 57.26**	$ 111.11
WCS blend differential from WTI (US$/bbl)	**$ 10.06**	$ 7.43	$ 17.98	**$ 8.83**	$ 20.33
WCS blend differential from WTI (%)	**15%**	13%	15%	**15%**	18%
SCO price (US$/bbl)	**$ 67.20**	$ 58.42	$ 121.96	**$ 56.95**	$ 117.20
Condensate benchmark price (US$/bbl)	**$ 65.80**	$ 58.30	$ 118.57	**$ 55.93**	$ 113.89
NYMEX benchmark price (US$/mmbtu)	**$ 3.42**	$ 3.59	$ 10.11	**$ 3.96**	$ 9.66
AECO benchmark price (C$/GJ)	**$ 2.87**	$ 3.46	$ 8.78	**$ 3.88**	$ 8.16
US / Canadian dollar average exchange rate	**$ 0.9108**	$ 0.8571	$ 0.9605	**$ 0.8549**	$ 0.9819

Commodity Prices

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$57.13 per bbl for the nine months ended September 30, 2009, a decrease of 50% from US$113.38 per bbl for the nine months ended September 30, 2008. WTI averaged US$68.29 per bbl for the third quarter of 2009, a decrease of 42% from US$118.13 per bbl for the third quarter of 2008, and an increase of 15% from US$59.61 per bbl for the prior quarter. WTI pricing was impacted by strong Asian demand, partially offset by declines in the European and North American markets due to weak economic activity.

Crude oil sales contracts for the Company's North Sea and Offshore West Africa segments are typically based on Dated Brent ("Brent") pricing, which is more reflective of international markets and the overall supply and demand balance. Brent averaged US$57.26 per bbl for the nine months ended September 30, 2009, a decrease of 48% compared to US$111.11 per bbl for the nine months ended September 30, 2008. Brent averaged US$68.28 per bbl for the third quarter of 2009, a decrease of 41% compared to US$114.96 per bbl for the third quarter of 2008, and an increase of 16% from US$58.78 per bbl for the prior quarter. The differential between Brent and WTI was impacted by the record high inventory levels at Cushing, Oklahoma during the third quarter of 2009.

The Heavy Differential averaged 15% for the nine months ended September 30, 2009 compared to 18% for the nine months ended September 30, 2008. The Heavy Differential averaged 15% for the third quarter of 2009 and 2008, and 13% for the prior quarter. The narrow Heavy Differential continued to reflect the relatively weak refinery margins.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the timing and extent of recovery of the global economy. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$3.96 per mmbtu for the nine months ended September 30, 2009, a decrease of 59% from US$9.66 per mmbtu for the nine months ended September 30, 2008. NYMEX natural gas prices averaged US$3.42 per mmbtu for the third quarter of 2009, a decrease of 66% from US$10.11 per mmbtu for the third quarter of 2008, and a decrease of 5% from US$3.59 per mmbtu for the prior quarter. AECO natural gas prices for the nine months ended September 30, 2009 decreased 52% to average $3.88 per GJ from $8.16 per GJ for the nine months ended September 30, 2008. AECO natural gas prices for the third quarter of 2009 decreased 67% to average $2.87 per GJ from $8.78 per GJ in the third quarter of 2008, and decreased 17% from $3.46 per GJ for the prior quarter. Decreases in natural gas prices from the comparable periods were primarily related to record storage levels in North America due to an oversupply in the market. During October 2009, natural gas pricing began to improve due to seasonal demands and production shut ins by producers.

Update to Alberta Royalty Framework

Effective January 1, 2009, changes to the Alberta royalty regime under the Alberta Royalty Framework (“ARF”) include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing.

In addition, effective January 1, 2009, new royalty formulas under the ARF for conventional crude oil and natural gas operate on sliding scales ranging up to 50%, determined by commodity prices and well productivity.

In March 2009, the Government of Alberta announced new incentive programs to stimulate activity in Alberta. These programs provide for:

- A royalty credit of $200 per meter on new conventional crude oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, to a maximum of 10% of conventional Crown royalties paid in Alberta.
- Reduced royalty rates that set the maximum royalty at 5% for the first 12 months of production, up to a maximum of 50,000 bbl or 500 mmcf, for new conventional crude oil and natural gas wells that commence production between April 1, 2009 and March 31, 2010.

In June 2009, the Government of Alberta extended the two incentive programs described above by one year, to March 31, 2011.

Province of British Columbia Oil and Gas Stimulus Package

Effective September 1, 2009, the Province of British Columbia announced an oil and gas stimulus package that includes:

- A one-year, 2% royalty rate for all natural gas wells drilled between September 1, 2009 and June 30, 2010. Qualifying wells must commence production before December 31, 2010.
- A permanent increase of 15% in the existing royalty holiday credits for natural gas deep drilling.
- Permanent qualification of horizontal wells drilled between 1,900 and 2,300 meters into the Deep Royalty Credit Program.
- An additional $50 million allocation for the Infrastructure Royalty Credit Program to stimulate investment in oil and gas roads and pipelines.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs (bbl/d)					
North America – Conventional	**223,307**	232,139	239,973	**236,315**	244,832
North America – Oil Sands Mining and Upgrading	**66,907**	59,599	–	**43,529**	–
North Sea	**34,034**	40,362	42,760	**38,891**	46,041
Offshore West Africa	**35,021**	33,572	24,237	**33,025**	26,842
	359,269	365,672	306,970	**351,760**	317,715
Natural gas (mmcf/d)					
North America	**1,264**	1,322	1,467	**1,311**	1,494
North Sea	**8**	10	9	**9**	10
Offshore West Africa	**21**	20	14	**18**	14
	1,293	1,352	1,490	**1,338**	1,518
Total barrels of oil equivalent (boe/d)	**574,755**	590,984	555,356	**574,688**	570,704
Product mix					
Light/medium crude oil and NGLs	**20%**	21%	21%	**21%**	22%
Pelican Lake crude oil	**6%**	6%	7%	**6%**	7%
Primary heavy crude oil	**15%**	14%	16%	**15%**	16%
Thermal heavy crude oil	**9%**	11%	11%	**11%**	11%
Synthetic crude oil	**12%**	10%	–	**8%**	–
Natural gas	**38%**	38%	45%	**39%**	44%
Percentage of gross revenue (1) (excluding midstream revenue)					
Crude oil and NGLs	**79%**	79%	70%	**74%**	69%
Natural gas	**21%**	21%	30%	**26%**	31%

(1) Net of transportation and blending costs and excluding risk management activities.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs (bbl/d)					
North America – Conventional	**191,077**	197,281	202,419	**204,166**	207,072
North America – Oil Sands Mining and Upgrading	**64,814**	58,467	–	**42,439**	–
North Sea	**33,961**	40,292	42,665	**38,809**	45,945
Offshore West Africa	**30,551**	30,470	19,050	**29,795**	22,216
	320,403	326,510	264,134	**315,209**	275,233
Natural gas (mmcf/d)					
North America	**1,228**	1,313	1,217	**1,241**	1,234
North Sea	**8**	10	9	**9**	10
Offshore West Africa	**18**	18	11	**16**	12
	1,254	1,341	1,237	**1,266**	1,256
Total barrels of oil equivalent (boe/d)	**529,421**	550,053	470,268	**526,184**	484,593

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil, thermal heavy crude oil, and SCO.

Total crude oil and NGLs production for the nine months ended September 30, 2009 increased 11% to 351,760 bbl/d from 317,715 bbl/d for the nine months ended September 30, 2008. The increase from the comparable period was primarily due to the commencement of production from Horizon and the Olowi Field in Offshore Gabon and the restoration of some of the production in the Baobab Field.

Total crude oil and NGLs production for the third quarter of 2009 increased 17% to 359,269 bbl/d from 306,970 bbl/d for the third quarter of 2008, and decreased 2% from 365,672 bbl/d for the prior quarter. The increase from the third quarter in 2008 was primarily due to production from Horizon and the Olowi Field in Offshore Gabon. The decrease from the prior quarter was in line with expectations and primarily due to the cyclic nature of the Company's thermal production and the timing of planned maintenance activities in the North Sea. Crude oil and NGLs production in the third quarter of 2009 was slightly below the Company's previously issued guidance of 363,000 to 389,000 bbl/d due to lower than targeted production from Horizon.

Natural gas production continued to represent the Company's largest product offering for the nine months ended September 30, 2009, accounting for 39% of the Company's total production. Natural gas production for the nine months ended September 30, 2009 averaged 1,338 mmcf/d compared to 1,518 mmcf/d for the nine months ended September 30, 2008. Natural gas production for the third quarter of 2009 averaged 1,293 mmcf/d compared to 1,490 mmcf/d for the third quarter of 2008 and 1,352 mmcf/d for the prior quarter. The decrease in natural gas production from the comparable periods reflects the expected production declines due to the Company's strategic reduction in natural gas drilling activity. Natural gas production in the third quarter of 2009 was within the Company's previously issued guidance of 1,274 to 1,304 mmcf/d.

For 2009, revised annual production guidance is targeted to average between 352,000 and 363,000 bbl/d of crude oil and NGLs and between 1,305 and 1,314 mmcf/d of natural gas. Fourth quarter 2009 production guidance is targeted to average between 359,000 and 390,000 bbl/d of crude oil and NGLs and between 1,213 and 1,243 mmcf/d of natural gas.

North America – Conventional

North America conventional crude oil and NGLs production for the nine months ended September 30, 2009 decreased 3% to average 236,315 bbl/d from 244,832 bbl/d for the nine months ended September 30, 2008. Third quarter North America conventional crude oil and NGLs production decreased 7% to average 223,307 bbl/d from 239,973 bbl/d for the third quarter of 2008, and decreased 4% from 232,139 bbl/d for the prior quarter. The decrease in crude oil and NGLs production from the prior periods was primarily due to the cyclic nature of the Company's thermal production and was in line with expectations. Production of conventional crude oil and NGLs was at the high end of the Company's previously issued guidance of 215,000 bbl/d to 225,000 bbl/d for the third quarter of 2009.

Natural gas production for the nine months ended September 30, 2009 decreased 12% to 1,311 mmcf/d from 1,494 mmcf/d for the nine months ended September 30, 2008. For the third quarter of 2009, natural gas production decreased 14% to 1,264 mmcf/d from 1,467 mmcf/d for the third quarter of 2008, and decreased 4% from 1,322 mmcf/d for the prior quarter. The decreases in natural gas production were consistent with the Company's strategic decision to reduce natural gas drilling activity.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 achieved first production of synthetic crude oil during 2009. Production averaged 43,529 bbl/day for the nine months ended September 30, 2009 and 66,907 bbl/d in the third quarter of 2009. Production volumes fluctuated throughout the quarter as the Company continued to stabilize and ramp up production. Production was impacted by premature equipment failures and ore processing challenges, and was below the Company's previously issued guidance of 80,000 bbl/d to 90,000 bbl/d for the third quarter of 2009. The Company believes it has largely worked through the matters associated with equipment and plant reliability. The ore processing challenges associated with a higher percentage of clays are expected to be resolved by the end of the second quarter of 2010.

North Sea

North Sea crude oil production for the nine months ended September 30, 2009 decreased 16% to 38,891 bbl/d from 46,041 bbl/d for the nine months ended September 30, 2008. Third quarter North Sea crude oil production decreased 20% to 34,034 bbl/d from 42,760 bbl/d for the third quarter of 2008 and 16% from 40,362 bbl/d for the prior quarter. Production in the third quarter of 2009 was at the low end of the Company's previously issued guidance and reflected planned maintenance shutdowns at all three Ninian platforms and the Tiffany platform.

Offshore West Africa

Offshore West Africa crude oil production increased 23% to 33,025 bbl/d for the nine months ended September 30, 2009 from 26,842 bbl/d for the nine months ended September 30, 2008. Third quarter Offshore West Africa crude oil production increased 44% to 35,021 bbl/d from 24,237 bbl/d for the third quarter of 2008, and 4% from 33,572 bbl/d for the prior quarter.

During the third quarter, two new wells were tied in at the Olowi Field and production averaged approximately 4,400 bbl/d. Production to date from the first platform has been below expectations. The Company is currently reviewing drilling results and production data to determine the root cause of well performance issues in order to develop appropriate remediation strategies and determine the impact on future production from the Field and the impact on recoverable reserves. While the Company continues drilling at the next scheduled platform, it is reviewing ongoing and future development activities, which may result in changes to the scope of the overall development plan. At September 30, 2009, the Company had incurred approximately $940 million related to development of the Olowi project.

Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or floating production, storage and offtake vessels, as follows:

(bbl)	**Sep 30 2009**	Jun 30 2009	Dec 31 2008
North America – Conventional	**761,351**	901,053	761,351
North America – Oil Sands Mining and Upgrading (SCO)	**1,035,573**	1,465,288	–
North Sea	**1,200,129**	923,645	558,904
Offshore West Africa	**367,531**	155,953	609,444
	3,364,584	3,445,939	1,929,699

OPERATING HIGHLIGHTS – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 62.90**	$ 59.56	$ 102.30	**$ 54.17**	$ 94.72
Royalties	**7.89**	7.27	14.17	**6.31**	12.49
Production expense	**16.71**	16.59	17.61	**16.08**	16.24
Netback	**$ 38.30**	$ 35.70	$ 70.52	**$ 31.78**	$ 65.99
Natural gas ($/mcf) (1)					
Sales price (2)	**$ 3.80**	$ 4.11	$ 8.82	**$ 4.46**	$ 8.83
Royalties (3)	**0.13**	0.06	1.55	**0.31**	1.59
Production expense	**1.05**	1.05	1.05	**1.09**	1.01
Netback	**$ 2.62**	$ 3.00	$ 6.22	**$ 3.06**	$ 6.23
Barrels of oil equivalent ($/boe) (1)					
Sales price (2)	**$ 45.52**	$ 44.52	$ 80.60	**$ 42.54**	$ 76.73
Royalties	**4.85**	4.34	12.06	**4.43**	11.22
Production expense	**12.26**	12.21	12.52	**12.07**	11.70
Netback	**$ 28.41**	$ 27.97	$ 56.02	**$ 26.04**	$ 53.81

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

PRODUCT PRICES – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 60.07**	$ 57.97	$ 99.05	**$ 51.36**	$ 89.83
North Sea	**$ 75.91**	$ 65.52	$ 109.82	**$ 65.16**	$ 111.82
Offshore West Africa	**$ 70.05**	$ 63.00	$ 125.71	**$ 61.92**	$ 110.93
Company average	**$ 62.90**	$ 59.56	$ 102.30	**$ 54.17**	$ 94.72
Natural gas ($/mcf) (1) (2)					
North America	**$ 3.76**	$ 4.06	$ 8.83	**$ 4.44**	$ 8.86
North Sea	**$ 5.70**	$ 3.84	$ 3.65	**$ 4.53**	$ 3.73
Offshore West Africa	**$ 5.72**	$ 7.34	$ 11.18	**$ 6.54**	$ 9.33
Company average	**$ 3.80**	$ 4.11	$ 8.82	**$ 4.46**	$ 8.83
Company average ($/boe) (1) (2)	**$ 45.52**	$ 44.52	$ 80.60	**$ 42.54**	$ 76.73

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

North America

North America realized crude oil prices decreased 43% to average $51.36 per bbl for the nine months ended September 30, 2009 from $89.83 per bbl for the nine months ended September 30, 2008. Realized crude oil prices decreased 39% to average $60.07 per bbl for the third quarter of 2009 from $99.05 per bbl for the third quarter of 2008, and increased 4% from $57.97 per bbl for the prior quarter. The decreases from the comparable periods in 2008 were primarily a result of decreased WTI benchmark pricing, partially offset by the impact of the narrowing of the Heavy Differential and the weaker Canadian dollar relative to the US dollar. The increase from the prior quarter was primarily the result of increased WTI benchmark pricing, partially offset by the impact of the stronger Canadian dollar relative to the US dollar.

The Company continues to focus on its crude oil marketing strategy, and in the third quarter of 2009 contributed approximately 124,000 bbl/d of heavy crude oil blends to the Western Canadian Select stream.

North America realized natural gas prices decreased 50% to average $4.44 per mcf for the nine months ended September 30, 2009 from $8.86 per mcf for the nine months ended September 30, 2008. Realized natural gas prices decreased 57% to average $3.76 per mcf for the third quarter of 2009 from $8.83 per mcf for the third quarter of 2008, and 7% from $4.06 per mcf for the prior quarter. The decreases in natural gas prices from the comparable periods were primarily related to lower benchmark prices due to lower demand and high storage levels in 2009.

Comparisons of the prices received for the Company's North America conventional production by product type were as follows:

	Sep 30 2009	Jun 30 2009	Sep 30 2008
Wellhead Price (1) (2)			
Light/medium crude oil and NGLs ($/bbl) (3)	**$ 59.24**	$ 56.00	$ 108.13
Pelican Lake crude oil ($/bbl)	**$ 61.11**	$ 59.94	$ 95.58
Primary heavy crude oil ($/bbl)	**$ 60.42**	$ 58.08	$ 97.30
Thermal heavy crude oil ($/bbl)	**$ 59.52**	$ 58.22	$ 97.06
Natural gas ($/mcf)	**$ 3.76**	$ 4.06	$ 8.83

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and blending costs and excluding risk management activities.

(3) Light/medium crude oil and NGLs wellhead pricing for the third and second quarter of 2009 reflected the impact of significant price discounts for certain types of NGLs, including propane and butane.

North Sea

North Sea realized crude oil prices decreased 42% to average $65.16 per bbl for the nine months ended September 30, 2009 from $111.82 per bbl for the nine months ended September 30, 2008. Realized crude oil prices decreased 31% to average $75.91 per bbl for the third quarter of 2009 from $109.82 per bbl for the third quarter of 2008, and increased 16% from $65.52 per bbl for the prior quarter. The decreases in realized crude oil prices in the North Sea from the comparable periods in 2008 were primarily the result of lower Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar. The increase from the prior quarter was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices decreased 44% to average $61.92 per bbl for the nine months ended September 30, 2009 from $110.93 per bbl for the nine months ended September 30, 2008. Realized crude oil prices decreased 44% to average $70.05 per bbl for the third quarter of 2009 from $125.71 per bbl for the third quarter of 2008, and increased 11% from $63.00 per bbl for the prior quarter. The decreases in realized crude oil prices in Offshore West Africa from the comparable periods in 2008 were primarily the result of lower Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar. The increase from the prior quarter was primarily the result of increased Brent benchmark pricing, partially offset by the impact of the stronger Canadian dollar. Realized crude oil prices in Offshore West Africa were also impacted by the timing of liftings from each field.

ROYALTIES – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 8.80**	$ 8.83	$ 15.76	**$ 7.30**	$ 14.26
North Sea	**$ 0.16**	$ 0.11	$ 0.24	**$ 0.13**	$ 0.23
Offshore West Africa	**$ 8.94**	$ 5.82	$ 26.90	**$ 6.03**	$ 18.89
Company average	**$ 7.89**	$ 7.27	$ 14.17	**$ 6.31**	$ 12.49
Natural gas ($/mcf) [1]					
North America [2]	**$ 0.12**	$ 0.05	$ 1.55	**$ 0.30**	$ 1.60
Offshore West Africa	**$ 0.74**	$ 0.63	$ 2.24	**$ 0.64**	$ 1.59
Company average	**$ 0.13**	$ 0.06	$ 1.55	**$ 0.31**	$ 1.59
Company average ($/boe) [1]	**$ 4.85**	$ 4.34	$ 12.06	**$ 4.43**	$ 11.22
Percentage of revenue [3]					
Crude oil and NGLs	**13%**	12%	14%	**12%**	13%
Natural gas [2]	**3%**	2%	18%	**7%**	18%
Boe	**11%**	10%	15%	**10%**	15%

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

(3) Net of transportation and blending costs and excluding risk management activities.

North America

North America royalties for the nine months ended September 30, 2009, compared to the nine months ended September 30, 2008, reflect the impact of the change in the ARF and weaker realized commodity prices.

Crude oil and NGLs royalties averaged approximately 15% of revenues for the third quarter of 2009, compared to 16% for the third quarter in 2008 and 15% in the prior quarter. Crude oil and NGLs royalties per bbl are anticipated to average 13% to 15% of gross revenue for 2009.

Natural gas royalties averaged approximately 3% of revenues for the third quarter of 2009 compared to 18% for the third quarter of 2008 and 2% for the prior quarter. The decrease in natural gas royalty rates for the third quarter of 2009 compared to the prior year was due to the impact of low natural gas benchmark pricing. Natural gas royalties are anticipated to average 7% to 8% of gross revenue for 2009.

Offshore West Africa

Under the terms of the Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 13% for the third quarter of 2009 compared to 21% for the third quarter of 2008 and 9% for the prior quarter. Offshore West Africa royalty rates are anticipated to average 6% to 9% of gross revenue for 2009.

PRODUCTION EXPENSE – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 15.19**	$ 15.29	$ 16.23	**$ 15.01**	$ 15.17
North Sea	**$ 31.30**	$ 27.36	$ 29.21	**$ 26.96**	$ 25.52
Offshore West Africa	**$ 13.35**	$ 10.45	$ 7.74	**$ 11.76**	$ 8.60
Company average	**$ 16.71**	$ 16.59	$ 17.61	**$ 16.08**	$ 16.24
Natural gas ($/mcf) (1)					
North America	**$ 1.04**	$ 1.04	$ 1.03	**$ 1.08**	$ 0.99
North Sea	**$ 1.57**	$ 1.62	$ 3.09	**$ 1.69**	$ 2.68
Offshore West Africa	**$ 1.37**	$ 1.36	$ 1.58	**$ 1.44**	$ 1.36
Company average	**$ 1.05**	$ 1.05	$ 1.05	**$ 1.09**	$ 1.01
Company average ($/boe) (1)	**$ 12.26**	$ 12.21	$ 12.52	**$ 12.07**	$ 11.70

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2009 decreased 1% to $15.01 per bbl from $15.17 per bbl for the nine months ended September 30, 2008. Production expense for the third quarter of 2009 decreased 6% to $15.19 per bbl from $16.23 per bbl for the third quarter of 2008 and 1% from $15.29 per bbl for the prior quarter. The decrease in production expense per barrel for the third quarter of 2009 was a result of the Company's focus on optimizing costs and lower power prices and the cost of natural gas used for fuel, partially offset by increased property taxes. North America crude oil and NGLs production expense is anticipated to average $14.85 to $15.05 per bbl for 2009.

North America natural gas production expense for the nine months ended September 30, 2009 increased 9% to $1.08 per mcf from $0.99 per mcf for the nine months ended September 30, 2008. Production expense for the third quarter of 2009 increased 1% to $1.04 per mcf from $1.03 per mcf for the third quarter of 2008 and was comparable to the prior quarter. The slight increase in production expense per mcf from the comparable periods in 2008 was primarily a result of lower production volumes on fixed costs, offset by reductions due to the Company's focus on optimizing costs and lower power prices. North America natural gas production expense is anticipated to average $1.05 to $1.10 per mcf for 2009.

North Sea

North Sea crude oil production expense increased on a per barrel basis from the prior quarter due to the impact of lower production volumes on a relatively fixed cost operating base. Production expense is anticipated to average $27.50 to $28.50 per bbl for 2009.

Offshore West Africa

Offshore West Africa crude oil production expense increased from the prior quarter on a per barrel basis. Production expense was impacted by the timing of liftings of each field. Production expense is anticipated to average $12.50 to $13.50 per bbl for 2009.

DEPLETION, DEPRECIATION AND AMORTIZATION – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Expense ($ millions)	**$ 610**	$ 631	$ 657	**$ 1,902**	$ 2,011
$/boe (1)	**$ 12.64**	$ 13.07	$ 12.93	**$ 13.14**	$ 12.89

(1) Amounts expressed on a per unit basis are based on sales volumes.

The decrease in Conventional Depletion, Depreciation and Amortization expense from the prior periods was primarily due to the impact of lower sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – CONVENTIONAL

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Expense ($ millions)	**$ 17**	$ 18	$ 18	**$ 52**	$ 52
$/boe (1)	**$ 0.36**	$ 0.36	$ 0.35	**$ 0.36**	$ 0.33

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2009**	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
SCO sales price (2)	**$ 69.11**	$ 65.40	$ –	**$ 67.65**	$ –
Bitumen value for royalty purposes	**$ 56.79**	$ 54.00	$ –	**$ 55.40**	$ –
Bitumen royalties (3)	**$ 2.19**	$ 0.76	$ –	**$ 1.63**	$ –

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of transportation and excluding risk management activities.

(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

PRODUCTION COSTS

The following tables provide reconciliations of Oil Sands Mining and Upgrading production costs to the Segmented Information disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2009**	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Cash costs, excluding natural gas costs	**$ 212**	$ 159	$ –	**$ 371**	$ –
Natural gas costs	**30**	23	–	**53**	–
Total cash production costs	**$ 242**	$ 182	$ –	**$ 424**	$ –

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2009**	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Cash costs, excluding natural gas costs	**$ 32.36**	$ 37.15	$ –	**$ 34.24**	$ –
Natural gas costs	**4.49**	5.50	–	**4.89**	–
Total cash production costs	**$ 36.85**	$ 42.65	$ –	**$ 39.13**	$ –
Sales (bbl/d)	**71,578**	46,844	–	**39,736**	–

(1) Amounts expressed on a per unit basis are based on sales volumes.

First sales from Horizon occurred in the second quarter of 2009.

Production expense in the third quarter of 2009 continued to reflect the effects of the commencement of operations. Total cash production costs averaged $36.85 per bbl in the third quarter of 2009, and are targeted to average $35.00 to $45.00 per bbl for the year.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2009**	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Depreciation, depletion and amortization	**$ 66**	$ 36	$ –	**$ 104**	$ –
Asset retirement obligation accretion	**7**	6	–	**15**	–
Total	**$ 73**	$ 42	$ –	**$ 119**	$ –

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2009**	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Depreciation, depletion and amortization	**$ 9.99**	$ 8.51	$ –	**$ 9.61**	$ –
Asset retirement obligation accretion	**0.95**	1.47	–	**1.35**	–
Total	**$ 10.94**	$ 9.98	$ –	**$ 10.96**	$ –

(1) Amounts expressed on a per unit basis are based on sales volumes.

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs has ceased, and depletion, depreciation and amortization of these assets has commenced.

MIDSTREAM

($ millions)	Three Months Ended Sep 30 2009	Jun 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Revenue	**$ 18**	$ 17	$ 20	**$ 54**	$ 60
Production expense	**4**	5	6	**14**	19
Midstream cash flow	**14**	12	14	**40**	41
Depreciation	**2**	2	2	**6**	6
Segment earnings before taxes	**$ 12**	$ 10	$ 12	**$ 34**	$ 35

Midstream operating results were consistent with the comparable periods.

ADMINISTRATION EXPENSE

	Three Months Ended Sep 30 2009	Jun 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Expense ($ millions)	**$ 38**	$ 47	$ 46	**$ 132**	$ 134
$/boe (1)	**$ 0.72**	$ 0.88	$ 0.91	**$ 0.85**	$ 0.86

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for the third quarter of 2009 decreased from the prior quarter primarily related to lower staffing related costs. Administration expense on a boe basis in 2009 includes sales volumes associated with the commencement of Horizon.

STOCK-BASED COMPENSATION EXPENSE

($ millions)	Three Months Ended Sep 30 2009	Jun 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Expense	**$ 172**	$ 92	$ (308)	**$ 268**	$ 151

The Company recorded a $268 million ($196 million after-tax) stock-based compensation expense for the nine months ended September 30, 2009 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the period, and the 48% increase in the Company’s share price, including a $172 million ($126 million after-tax) stock-based compensation expense for the three months ended September 30, 2009 (Company’s share price as at: September 30, 2009 – $72.30; June 30, 2009 – $61.19; December 31, 2008 – $48.75; September 30, 2008 – $73.00). For the nine months ended September 30, 2009, the Company recorded a $2 million recovery on previously capitalized stock-based compensation to Oil Sands Mining and Upgrading (September 30, 2008 – $33 million capitalized). The stock-based compensation liability reflected the Company’s potential cash liability should all the vested options be surrendered for a cash payout at the market price on September 30, 2009.

For the nine months ended September 30, 2009, the Company paid $79 million for stock options surrendered for cash settlement (September 30, 2008 – $202 million).

INTEREST EXPENSE

($ millions, except per boe amounts)	Three Months Ended Sep 30 2009	Three Months Ended Jun 30 2009	Three Months Ended Sep 30 2008	Nine Months Ended Sep 30 2009	Nine Months Ended Sep 30 2008
Expense, gross	**$ 124**	$ 130	$ 150	**$ 397**	$ 451
Less: capitalized interest, Oil Sands Mining and Upgrading	**6**	6	125	**98**	346
Expense, net	**$ 118**	$ 124	$ 25	**$ 299**	$ 105
$/boe [(1)]	**$ 2.23**	$ 2.36	$ 0.49	**$ 1.92**	$ 0.67
Average effective interest rate	**4.3%**	4.1%	5.0%	**4.2%**	5.2%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest expense decreased from the comparable periods in 2008 primarily due to lower variable interest rates and debt repayment, partially offset by fluctuations in foreign exchange rates on US dollar denominated debt. The Company's average effective interest rate decreased from the comparable periods in 2008 primarily due to lower variable interest rates.

During the first quarter of 2009, interest capitalization ceased on Horizon Phase 1, increasing net interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, currency and interest rate exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)	Three Months Ended Sep 30 2009	Three Months Ended Jun 30 2009	Three Months Ended Sep 30 2008	Nine Months Ended Sep 30 2009	Nine Months Ended Sep 30 2008
Crude oil and NGLs financial instruments	**$ (235)**	$ (362)	$ 792	**$ (1,182)**	$ 2,199
Natural gas financial instruments	**–**	(1)	16	**(33)**	(21)
Foreign currency contracts and interest rate swaps	**35**	73	(17)	**84**	(17)
Realized (gain) loss	**$ (200)**	$ (290)	$ 791	**$ (1,131)**	$ 2,161
Crude oil and NGLs financial instruments	**$ 208**	$ 1,020	$ (2,423)	**$ 1,711**	$ (992)
Natural gas financial instruments	**(4)**	(13)	(68)	**(41)**	29
Foreign currency contracts and interest rate swaps	**70**	(61)	(15)	**13**	(20)
Unrealized loss (gain)	**$ 274**	$ 946	$ (2,506)	**$ 1,683**	$ (983)
Net loss (gain)	**$ 74**	$ 656	$ (1,715)	**$ 552**	$ 1,178

Complete details related to outstanding derivative financial instruments at September 30, 2009 are disclosed in note 11 to the Company’s unaudited interim consolidated financial statements.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,683 million ($1,213 million after-tax) on its risk management activities for the nine months ended September 30, 2009, including a $274 million ($217 million after-tax) net unrealized loss for the third quarter of 2009 (June 30, 2009 – unrealized loss of $946 million, $676 million after-tax; September 30, 2008 – unrealized gain of $2,506 million, $1,750 million after-tax).

FOREIGN EXCHANGE

($ millions)	Three Months Ended Sep 30 2009	Jun 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Net realized (gain) loss	**$ (33)**	$ 74	$ (40)	**$ 26**	$ (63)
Net unrealized (gain) loss [1]	**(391)**	(320)	113	**(573)**	219
Net (gain) loss	**$ (424)**	$ (246)	$ 73	**$ (547)**	$ 156

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net unrealized foreign exchange gain for the nine months ended September 30, 2009 was primarily due to the strengthening of the Canadian dollar with respect to the US dollar debt, offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling. Also included in net unrealized (gain) loss for the respective periods was the impact of cross currency swaps (three months ended September 30, 2009 – unrealized loss of $172 million, June 30, 2009 – unrealized loss of $186 million, September 30, 2008 – unrealized gain of $78 million; nine months ended September 30, 2009 – unrealized loss of $290 million, September 30, 2008 – unrealized gain of $136 million). The net realized foreign exchange loss for the nine months ended September 30, 2009 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The Canadian dollar ended the third quarter at US$0.9327 (June 30, 2009 – US$0.8602; December 31, 2008 – US$0.8166; September 30, 2008 – US$0.9435).

TAXES

($ millions, except income tax rates)	Three Months Ended Sep 30 2009	Jun 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Current	**$ 10**	$ 49	$ 52	**$ 66**	$ 218
Deferred	**13**	(2)	(7)	**8**	(62)
Taxes other than income tax	**$ 23**	$ 47	$ 45	**$ 74**	$ 156
North America [1]	**$ 7**	$ 5	$ 6	**$ 17**	$ 33
North Sea	**55**	65	121	**218**	328
Offshore West Africa	**28**	17	44	**59**	116
Current income tax	**90**	87	171	**294**	477
Future income tax expense (recovery)	**83**	(201)	1,011	**(174)**	790
	173	(114)	1,182	**120**	1,267
Income tax rate and other legislative changes [2] [3]	**–**	–	–	**19**	41
	$ 173	$ (114)	$ 1,182	**$ 139**	$ 1,308
Effective income tax rate on adjusted net earnings from operations	**25.7%**	16.8%	26.8%	**22.9%**	27.8%

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

(2) Includes the effect of a one time recovery of $19 million due to British Columbia corporate income tax rate reductions substantively enacted or enacted during the first quarter of 2009.

(3) Includes the effect of a one time recovery of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions substantively enacted or enacted during the first quarter of 2008.

CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2009	Jun 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Expenditures on property, plant and equipment					
Net property (dispositions) acquisitions	**$ (30)**	$ (2)	$ 47	**$ (5)**	$ 302
Land acquisition and retention	**18**	18	32	**49**	68
Seismic evaluations	**21**	11	40	**60**	85
Well drilling, completion and equipping	**261**	194	421	**953**	1,159
Production and related facilities	**235**	230	311	**755**	900
Total net reserve replacement expenditures	**505**	451	851	**1,812**	2,514
Oil Sands Mining and Upgrading:					
Horizon Phase 1 construction costs	**–**	(59)	635	**69**	2,175
Horizon Phase 1 commissioning and other costs	**–**	46	111	**202**	249
Horizon Phases 2/3 construction costs	**21**	22	83	**62**	242
Capitalized interest, stock-based compensation and other	**11**	(4)	46	**86**	402
Sustaining capital	**23**	4	-	**27**	-
Total Oil Sands Mining and Upgrading [2]	**55**	9	875	**446**	3,068
Midstream	**–**	–	2	**5**	6
Abandonments [3]	**12**	10	10	**31**	23
Head office	**2**	3	6	**9**	13
Total net capital expenditures	**$ 574**	$ 473	$ 1,744	**$ 2,303**	$ 5,624
By segment					
North America	**$ 358**	$ 270	$ 578	**$ 1,227**	$ 1,858
North Sea	**38**	40	78	**120**	202
Offshore West Africa	**108**	141	195	**464**	453
Other	**1**	–	–	**1**	1
Oil Sands Mining and Upgrading	**55**	9	875	**446**	3,068
Midstream	**–**	–	2	**5**	6
Abandonments [3]	**12**	10	10	**31**	23
Head office	**2**	3	6	**9**	13
Total	**$ 574**	$ 473	$ 1,744	**$ 2,303**	$ 5,624

(1) The net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.

(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core regions where it can dominate the land base and infrastructure. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the nine months ended September 30, 2009 were $2,303 million compared to $5,624 million for the nine months ended September 30, 2008. Net capital expenditures for the third quarter of 2009 were $574 million compared to $1,744 million for the third quarter of 2008 and $473 million for the prior quarter. The decrease in capital expenditures from the prior year reflects the completion of Horizon Phase 1 construction. The increase in capital expenditures from the prior quarter reflects increased drilling activities in the third quarter of 2009. Capital expenditures were also impacted by the effects of an overall strategic reduction in the North America natural gas drilling program.

Drilling Activity (number of wells)

	Three Months Ended			Nine Months Ended	
	Sep 30 2009	Jun 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Net successful natural gas wells	**17**	–	62	**81**	228
Net successful crude oil wells	**262**	94	234	**449**	500
Dry wells	**10**	4	11	**29**	28
Stratigraphic test / service wells	**6**	7	8	**249**	34
Total	**295**	105	315	**808**	790
Success rate (excluding stratigraphic test / service wells)	**97%**	96%	96%	**95%**	96%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 55% of the total capital expenditures for the nine months ended September 30, 2009 compared to approximately 34% for the nine months ended September 30, 2008.

During the third quarter of 2009, the Company targeted 17 net natural gas wells, including 2 wells in Northeast British Columbia, 8 wells in the Northern Plains region, 6 wells in Northwest Alberta, and 1 well in the Southern Plains region. The Company also targeted 270 net crude oil wells. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 217 heavy crude oil wells, 19 Pelican Lake crude oil wells, and 24 thermal crude oil wells were drilled. Another 10 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years, a low natural gas price, and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. Overall Primrose thermal production for the third quarter of 2009 averaged approximately 52,000 bbl/d, compared to approximately 61,000 bbl/d for the third quarter of 2008 and approximately 63,000 bbl/d for the prior quarter. The Primrose East expansion was completed and first steaming commenced in September 2008, with first production achieved in the fourth quarter of 2008. During the first quarter of 2009, operational issues on one of the pads has caused steaming to cease on all well pads in the Primrose East project area. During the third quarter of 2009, the Company, upon receipt of regulatory approval, began diagnostic steaming and is continuing to work on resolving the issue.

The next planned phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project. Final corporate sanction and project scope is targeted for 2010. Currently the Company is looking to proceed with the detailed engineering and design work.

Development of new pads and secondary recovery conversion projects at Pelican Lake continued as expected throughout the third quarter of 2009. Drilling consisted of 19 horizontal wells in the third quarter. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d for the third quarter of 2009 and for the third quarter of 2008 and 36,000 bbl/d for the prior quarter.

For the fourth quarter of 2009, the Company's overall planned drilling activity in North America is expected to be comprised of 25 natural gas wells and 223 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

With construction completed, Horizon Phase 1 assets are now available for their intended use. Accordingly, capitalization of all associated development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs have ceased, and depletion, depreciation and amortization of these assets has commenced.

North Sea

In the third quarter of 2009, the Company completed planned maintenance shutdowns at two of the Ninian platforms and the Tiffany platform. The Company also commenced a planned maintenance shutdown at the third Ninian platform, which was completed on schedule early in the fourth quarter of 2009.

Offshore West Africa

During the third quarter of 2009, 1.9 net crude oil wells were drilled at the Olowi Field in Offshore Gabon and the drilling rig was moved to the second platform. Facilities construction continued during the quarter with the decks being installed on the three wellhead towers.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2009**	Jun 30 2009	Dec 31 2008	Sep 30 2008
Working capital (deficit) [1]	**$ (396)**	$ (113)	$ 392	$ (1,103)
Long-term debt [2] [3]	**$ 10,557**	$ 11,987	$ 13,016	$ 11,633
Share capital	**$ 2,827**	$ 2,816	$ 2,768	$ 2,761
Retained earnings	**16,299**	15,697	15,344	13,628
Accumulated other comprehensive (loss) income	**(61)**	75	262	116
Shareholders' equity	**$ 19,065**	$ 18,588	$ 18,374	$ 16,505
Debt to book capitalization [3] [4]	**36%**	39%	41%	41%
Debt to market capitalization [3] [5]	**21%**	27%	33%	23%
After tax return on average common shareholders' equity [6]	**16%**	30%	33%	29%
After tax return on average capital employed [3] [7]	**10%**	18%	19%	16%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt (September 30, 2009 – $nil; June 30, 2009 – $nil; December 31, 2008 – $420 million; September 30, 2008 – $nil).

(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.

(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.

(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

(7) Calculated as net earnings plus after-tax interest expense for the twelve month trailing period; as a percentage of average capital employed for the period. Average capital employed is the average shareholders' equity and current and long-term debt for the period, including $12,642 million in average capital employed related to Oil Sands Mining and Upgrading assets (June 30, 2009 – $12,209 million; December 31, 2008 – $10,678 million; September 30, 2008 – $9,725 million).

At September 30, 2009, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's December 31, 2008 annual MD&A**.** The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as maintaining an investment grade debt rating and the condition of capital and credit markets.

The uncertainties created by the worldwide financial and economic events over the past several quarters appear to be lessening in intensity as liquidity continues to return to the capital markets and financial institutions re-establish confidence in their balance sheets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms, will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

During the third quarter of 2009, the Company repaid the $1,370 million ($2,350 million at December 31, 2008) remaining on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation. At September 30, 2009, the Company had $1,261 million of available credit under its bank credit facilities. The Company's current debt ratings are BBB (high) with a stable trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's.

Further details related to the Company's long-term debt at September 30, 2009 are discussed in note 4 to the Company's unaudited interim consolidated financial statements.

Long-term debt was $10,557 million at September 30, 2009, resulting in a debt to book capitalization ratio of 36% (June 30, 2009 – 39%; December 31, 2008 – 41%; September 30, 2008 – 41%). This ratio is near the low end of the 35% to 45% range targeted by management. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. The Company has hedged a portion of its crude oil and natural gas production for 2009 and 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs.

Subsequent to September 30, 2009, the Company filed new base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this program, the purchase of put options is in addition to the above parameters. As at September 30, 2009, in accordance with the policy, approximately 6% of budgeted crude oil volumes were hedged using collars for the remainder of 2009 and approximately 23% of budgeted crude oil volumes and approximately 17% of budgeted natural gas volumes were hedged using collars for 2010. In addition, 92,000 bbl/d of crude oil volumes are protected by put options for the remainder of 2009 at a strike price of US$100.00 per bbl. Subsequent to September 30, 2009, the Company entered into 50,000 bbl/d of US$65.00 – US$105.49 WTI collars for the period January to September 2010.

Further details related to the Company's commodity related derivative financial instruments outstanding at September 30, 2009 are discussed in note 11 to the Company's unaudited interim consolidated financial statements.

Share capital

As at September 30, 2009, there were 542,238,000 common shares outstanding and 26,658,000 stock options outstanding. As at November 3, 2009, the Company had 542,295,000 common shares outstanding and 26,370,000 stock options outstanding.

In March 2009, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.42 per common share for 2009. The increase represented a 5% increase from 2008, recognizes the stability of the Company's cash flow, and provides a return to Shareholders. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Commitments and off balance sheet arrangements

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. As at September 30, 2009, no entities were consolidated under the Canadian Institute of Chartered Accountants Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at September 30, 2009:

($ millions)	Remaining 2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 59	$ 194	$ 157	$ 132	$ 124	$ 1,169
Offshore equipment operating leases	$ 51	$ 145	$ 126	$ 102	$ 103	$ 348
Offshore drilling	$ 42	$ 50	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 3	$ 10	$ 16	$ 17	$ 26	$ 5,739
Long-term debt (2)	$ –	$ 400	$ 429	$ 375	$ 829	$ 5,922
Interest expense (3)	$ 91	$ 487	$ 465	$ 427	$ 378	$ 5,242
Office leases	$ 6	$ 28	$ 22	$ 3	$ 2	$ 2
Other	$ 107	$ 189	$ 16	$ 9	$ 7	$ 18

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2009 – 2013 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $2,628 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at September 30, 2009.

Legal proceedings

The Company is defendant and plaintiff in a number of legal actions. In addition, the Company is subject to certain contractor construction claims related to Horizon. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

Critical accounting estimates and change in accounting policies

The preparation of financial statements requires the Company to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2008.

For the impact of new accounting standards related to goodwill and intangible assets, refer to note 2 of the unaudited interim consolidated financial statements as at September 30, 2009.

International Financial Reporting Standards

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board ("IASB") in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Senior Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project has been broken down into the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.
- Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.
- Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.
- Phase 5 Sustainment –ongoing compliance with IFRS after implementation.

The Company has completed the Diagnostic and Planning phases (Phases 1 and 2). Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, impairment testing, capitalized interest and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is continuing to perform the necessary research to develop and document IFRS policies to address the major differences noted. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, IFRS is expected to change prior to adoption in 2011, and the impact of these potential changes is not known. Included in the IFRS changes are amendments to IFRS 1 "Additional Exemptions for First-time Adopters" issued in July 2009 by the IASB, which prescribes transition exemptions for oil and gas companies following full cost accounting. The transition exemptions allow full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company intends to adopt the transition exemptions.

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the third quarter of 2009, excluding mark-to-market gains (losses) on risk management activities, and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [(1)]				
Excluding financial derivatives	$ 110	$ 0.20	$ 88	$ 0.16
Including financial derivatives	$ 100	$ 0.18	$ 79	$ 0.14
Natural gas – AECO C$0.10/mcf [(1)]				
Excluding financial derivatives	$ 28	$ 0.05	$ 23	$ 0.04
Including financial derivatives	$ 23	$ 0.04	$ 18	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 150	$ 0.28	$ 89	$ 0.17
Natural gas – 10 mmcf/d	$ 8	$ 0.01	$ 1	$ –
Foreign currency rate change				
$0.01 change in US$ [(1)]				
Including financial derivatives	$ 81 – 82	$ 0.15	$ 7 – 8	$ 0.01
Interest rate change – **1%**	$ 18	$ 0.03	$ 18	$ 0.03

(1) For details of outstanding financial instruments in place, refer to note 11 of the Company's unaudited interim consolidated financial statements.

FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars, unaudited)	Sep 30 2009	Dec 31 2008
ASSETS		
Current assets		
Cash and cash equivalents	**$ 14**	$ 27
Accounts receivable	**1,006**	1,059
Inventory, prepaids and other	**637**	455
Future income tax	**30**	–
Current portion of other long-term assets (note 3)	**149**	1,851
	1,836	3,392
Property, plant and equipment (note 13)	**38,996**	38,966
Other long-term assets (note 3)	**21**	292
	$ 40,853	$ 42,650
LIABILITIES		
Current liabilities		
Accounts payable	**$ 272**	$ 383
Accrued liabilities	**1,599**	1,802
Future income tax	**–**	585
Current portion of long-term debt (note 4)	**–**	420
Current portion of other long-term liabilities (note 5)	**361**	230
	2,232	3,420
Long-term debt (note 4)	**10,557**	12,596
Other long-term liabilities (note 5)	**1,493**	1,124
Future income tax	**7,506**	7,136
	21,788	24,276
SHAREHOLDERS' EQUITY		
Share capital (note 7)	**2,827**	2,768
Retained earnings	**16,299**	15,344
Accumulated other comprehensive (loss) income (note 8)	**(61)**	262
	19,065	18,374
	$ 40,853	$ 42,650

Commitments (note 12)

Consolidated Statements of Earnings

(millions of Canadian dollars, except per common share amounts, unaudited)	Three Months Ended **Sep 30 2009**	Three Months Ended Sep 30 2008	Nine Months Ended **Sep 30 2009**	Nine Months Ended Sep 30 2008
Revenue	**$ 2,823**	$ 4,583	**$ 7,759**	$ 13,662
Less: royalties	**(240)**	(612)	**(651)**	(1,749)
Revenue, net of royalties	**2,583**	3,971	**7,108**	11,913
Expenses				
Production	**813**	639	**2,168**	1,836
Transportation and blending	**241**	472	**867**	1,646
Depletion, depreciation and amortization	**673**	659	**1,983**	2,017
Asset retirement obligation accretion (note 5)	**24**	18	**67**	52
Administration	**38**	46	**132**	134
Stock-based compensation expense (recovery) (note 5)	**172**	(308)	**268**	151
Interest, net	**118**	25	**299**	105
Risk management activities (note 11)	**74**	(1,715)	**552**	1,178
Foreign exchange (gain) loss	**(424)**	73	**(547)**	156
	1,729	(91)	**5,789**	7,275
Earnings before taxes	**854**	4,062	**1,319**	4,638
Taxes other than income tax	**23**	45	**74**	156
Current income tax expense (note 6)	**90**	171	**294**	477
Future income tax expense (recovery) (note 6)	**83**	1,011	**(174)**	790
Net earnings	**$ 658**	$ 2,835	**$ 1,125**	$ 3,215
Net earnings per common share (note 10)				
Basic and diluted	**$ 1.21**	$ 5.25	**$ 2.07**	$ 5.95

Consolidated Statements of Shareholders' Equity

(millions of Canadian dollars, unaudited)	Nine Months Ended Sep 30 2009	Sep 30 2008
Share capital (note 7)		
Balance – beginning of period	**$ 2,768**	$ 2,674
Issued upon exercise of stock options	**21**	17
Previously recognized liability on stock options exercised for common shares	**38**	70
Balance – end of period	**2,827**	2,761
Retained earnings		
Balance – beginning of period	**15,344**	10,575
Net earnings	**1,125**	3,215
Dividends on common shares (note 7)	**(170)**	(162)
Balance – end of period	**16,299**	13,628
Accumulated other comprehensive (loss) income (note 8)		
Balance – beginning of period	**262**	72
Other comprehensive (loss) income, net of taxes	**(323)**	44
Balance – end of period	**(61)**	116
Shareholders' equity	**$ 19,065**	$ 16,505

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2009	Sep 30 2008	Nine Months Ended Sep 30 2009	Sep 30 2008
Net earnings	**$ 658**	$ 2,835	**$ 1,125**	$ 3,215
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $nil million (2008 – $13 million) – three months ended; $4 million (2008 – $2 million) – nine months ended	**6**	89	**(24)**	24
Reclassification to net earnings, net of taxes of $nil million (2008 – $1 million) – three months ended; $1 million (2008 – $6 million) – nine months ended	**(2)**	3	**(10)**	(11)
	4	92	**(34)**	13
Foreign currency translation adjustment				
Translation of net investment	**(140)**	18	**(289)**	31
Other comprehensive (loss) income, net of taxes	**(136)**	110	**(323)**	44
Comprehensive income	**$ 522**	$ 2,945	**$ 802**	$ 3,259

Consolidated Statements of Cash Flows

(millions of Canadian dollars, unaudited)	Three Months Ended **Sep 30 2009**	Three Months Ended Sep 30 2008	Nine Months Ended **Sep 30 2009**	Nine Months Ended Sep 30 2008
Operating activities				
Net earnings	**$ 658**	$ 2,835	**$ 1,125**	$ 3,215
Non-cash items				
Depletion, depreciation and amortization	**673**	659	**1,983**	2,017
Asset retirement obligation accretion	**24**	18	**67**	52
Stock-based compensation expense (recovery)	**172**	(308)	**268**	151
Unrealized risk management loss (gain)	**274**	(2,506)	**1,683**	(983)
Unrealized foreign exchange (gain) loss	**(391)**	113	**(573)**	219
Deferred petroleum revenue tax expense (recovery)	**13**	(7)	**8**	(62)
Future income tax expense (recovery)	**83**	1,011	**(174)**	790
Other	**8**	4	**2**	23
Abandonment expenditures	**(12)**	(10)	**(31)**	(23)
Net change in non-cash working capital	**58**	(132)	**(55)**	16
	1,560	1,677	**4,303**	5,415
Financing activities				
(Repayment) issue of bank credit facilities, net	**(798)**	331	**(1,304)**	(909)
Repayment of senior unsecured notes	**–**	–	**(34)**	(31)
(Repayment) issue of US dollar debt securities	**–**	(8)	**–**	1,215
Issue of common shares on exercise of stock options	**3**	3	**21**	17
Dividends on common shares	**(57)**	(54)	**(168)**	(154)
Net change in non-cash working capital	**(44)**	(32)	**(48)**	(2)
	(896)	240	**(1,533)**	136
Investing activities				
Expenditures on property, plant and equipment	**(588)**	(1,739)	**(2,305)**	(5,616)
Net proceeds on sale of property, plant and equipment	**26**	5	**33**	15
Net expenditures on property, plant and equipment	**(562)**	(1,734)	**(2,272)**	(5,601)
Net change in non-cash working capital	**(113)**	(191)	**(511)**	43
	(675)	(1,925)	**(2,783)**	(5,558)
Decrease in cash and cash equivalents	**(11)**	(8)	**(13)**	(7)
Cash and cash equivalents – beginning of period	**25**	22	**27**	21
Cash and cash equivalents – end of period	**$ 14**	$ 14	**$ 14**	$ 14
Interest paid	**$ 157**	$ 184	**$ 433**	$ 462
Taxes paid				
Taxes other than income tax	**$ 34**	$ 162	**$ 34**	$ 217
Current income tax	**$ 87**	$ 178	**$ 128**	$ 123

Notes to the consolidated financial statements
(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

The interim consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2008, except as described in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2008.

During 2009, Horizon Oil Sands ("Horizon") Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs have ceased, and depletion, depreciation and amortization of these assets has commenced. In addition, the Company has recognized additional asset retirement obligations related to its oil sands mining operations and tailings ponds (note 5). All Horizon related financial results are included in the "Oil Sands Mining and Upgrading" segment.

Comparative Figures

Certain prior period figures have been reclassified to conform to the presentation adopted in 2009.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2009, the Company adopted the following new accounting standard issued by the Canadian Institute of Chartered Accountants ("CICA"):

- **Goodwill and Intangible Assets** – Section 3064 – "Goodwill and Intangible Assets" replaces Section 3062 – "Goodwill and Other Intangible Assets" and Section 3450 – "Research and Development Costs". In addition, EIC-27 – "Revenue and Expenditures during the Pre-Operating Period" has been withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard, which was adopted retroactively without restatement, did not have an impact on the Company's financial statements.

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of generally accepted accounting principles in Canada ("GAAP") effective January 1, 2011. The Company continues to assess which accounting policies will be affected by the change to IFRS and the potential impact of these changes on its financial position and results of operations.

3. OTHER LONG–TERM ASSETS

	Sep 30 2009	Dec 31 2008
Risk management (note 11)	**$ 149**	$ 2,119
Other	**21**	24
	170	2,143
Less: current portion	**149**	1,851
	$ 21	$ 292

4. LONG–TERM DEBT

	Sep 30 2009	Dec 31 2008
Canadian dollar denominated debt		
Bank credit facilities (bankers' acceptances)	**$ 1,824**	$ 4,073
Medium-term notes	**1,200**	1,200
	3,024	5,273
US dollar denominated debt		
US dollar bank credit facilities (bankers' acceptances)		
(2009 – US$750 million; 2008 – US$nil)	**804**	–
Senior unsecured notes (2009 – US$nil; 2008 – US$31 million)	**–**	38
US dollar debt securities (2009 – US$6,300 million; 2008 – US$6,300 million)	**6,755**	7,715
Less: original issue discount on senior unsecured notes and US dollar debt securities (1)	**(22)**	(23)
	7,537	7,730
Fair value of interest rate swaps on US dollar debt securities (2)	**47**	68
	7,584	7,798
Long-term debt before transaction costs	**10,608**	13,071
Less: transaction costs (1) (3)	**(51)**	(55)
	10,557	13,016
Less: current portion	**–**	420
	$ 10,557	$ 12,596

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.

(2) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $47 million (2008 – $68 million) to reflect the fair value impact of hedge accounting.

(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank credit facilities

As at September 30, 2009, the Company had in place unsecured bank credit facilities of $3,956 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are extendible annually for one year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

During the third quarter of 2009, the Company repaid the $1,370 million ($2,350 million at December 31, 2008) remaining on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation and cancelled the facility.

During the second quarter of 2009, the Company renegotiated its demand credit facility, increasing it to $200 million.

The Company's weighted average interest rate on long-term debt outstanding as at September 30, 2009 was 4.5% (December 31, 2008 – 4.6%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $370 million, including $300 million related to Horizon, were outstanding at September 30, 2009.

Medium-term notes

Subsequent to September 30, 2009, the Company filed a new base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance. A previous base shelf prospectus expired in October 2009.

Senior unsecured notes

During the second quarter of 2009, US$31 million of senior unsecured notes were repaid.

US dollar debt securities

Subsequent to September 30, 2009, the Company filed a new base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance. A previous base shelf prospectus expired in October 2009.

5. OTHER LONG–TERM LIABILITIES

	Sep 30 2009	Dec 31 2008
Asset retirement obligations	**$ 1,338**	$ 1,064
Stock-based compensation	**320**	171
Risk management (note 11)	**90**	–
Other	**106**	119
	1,854	1,354
Less: current portion	**361**	230
	$ 1,493	$ 1,124

Asset retirement obligations

At September 30, 2009, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $5,811 million (December 31, 2008 – $4,474 million). These costs will be incurred over the lives of the operating assets and have been discounted using a weighted average credit-adjusted risk-free rate of 7.0% (December 31, 2008 – 6.7%). A reconciliation of the discounted asset retirement obligations is as follows:

	Nine Months Ended Sep 30, 2009	Year Ended Dec 31, 2008
Balance – beginning of period	**$ 1,064**	$ 1,074
Liabilities incurred [(1) (2)]	**298**	18
Liabilities acquired	**–**	3
Liabilities settled	**(31)**	(38)
Asset retirement obligation accretion	**67**	71
Revision of estimates	**–**	(156)
Foreign exchange	**(60)**	92
Balance – end of period	**$ 1,338**	$ 1,064

(1) During the first quarter of 2009, the Company recognized additional asset retirement obligations related to Horizon (discounted – $246 million, undiscounted – $1,350 million).

(2) During the second quarter of 2009, the Company recognized additional asset retirement obligations related to Gabon, Offshore West Africa (discounted – $46 million, undiscounted – $93 million).

Stock-based compensation

The Company recognizes a liability for the potential cash settlements under its Stock Option Plan. The current portion represents the maximum amount of the liability payable within the next twelve-month period if all vested options are surrendered for cash settlement.

	Nine Months Ended Sep 30, 2009	Year Ended Dec 31, 2008
Balance – beginning of period	**$ 171**	$ 529
Stock-based compensation expense (recovery)	**268**	(52)
Cash payments for options surrendered	**(79)**	(207)
Transferred to common shares	**(38)**	(76)
Recovery to Oil Sands Mining and Upgrading	**(2)**	(23)
Balance – end of period	**320**	171
Less: current portion	**270**	159
	$ 50	$ 12

6. INCOME TAXES

The provision for income taxes is as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Current income tax – North America [(1)]	**$ 7**	$ 6	**$ 17**	$ 33
Current income tax – North Sea	**55**	121	**218**	328
Current income tax – Offshore West Africa	**28**	44	**59**	116
Current income tax expense	**90**	171	**294**	477
Future income tax expense (recovery)	**83**	1,011	**(174)**	790
Income tax expense	**$ 173**	$ 1,182	**$ 120**	$ 1,267

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, North America and North Sea current income taxes will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During the first quarter of 2009, substantively enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia (2008 – $19 million reduction in British Columbia, $22 million reduction in Côte d'Ivoire).

7. SHARE CAPITAL

	Nine Months Ended Sep 30, 2009	
Issued Common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**540,991**	**$ 2,768**
Issued upon exercise of stock options	**1,247**	**21**
Previously recognized liability on stock options exercised	**–**	**38**
Balance – end of period	**542,238**	**$ 2,827**

Dividend policy

In March 2009, the Board of Directors set the regular quarterly dividend at $0.105 per common share. The Company has paid regular quarterly dividends in January, April, July, and October of each year since 2001. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change.

Stock options

	Nine Months Ended Sep 30, 2009	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**30,962**	**$ 51.94**
Granted	**625**	**$ 58.00**
Surrendered for cash settlement	**(2,418)**	**$ 25.48**
Exercised for common shares	**(1,247)**	**$ 17.68**
Forfeited	**(1,264)**	**$ 59.79**
Outstanding – end of period	**26,658**	**$ 55.71**
Exercisable – end of period	**8,268**	**$ 51.34**

8. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

The components of accumulated other comprehensive (loss) income, net of taxes, were as follows:

	Nine Months Ended	
	Sep 30 2009	Sep 30 2008
Derivative financial instruments designated as cash flow hedges	**$ 85**	$ 114
Foreign currency translation adjustment	**(146)**	2
	$ (61)	$ 116

9. CAPITAL DISCLOSURES

As required by Canadian GAAP, the Company must provide certain disclosures regarding its objectives, policies and processes for managing capital, as well as provide certain quantitative data about capital. As the Company does not have any externally imposed regulatory capital requirements, for the purposes of this disclosure, the Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived non-GAAP financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently near the low end of the target range at 36%.

Readers are cautioned that as the debt to book capitalization ratio has no defined meaning under GAAP, this financial measure may not be comparable to similar measures provided by other reporting entities. Further, there can be no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure at some point in the future.

	Sep 30 2009	Dec 31 2008
Long-term debt (1)	**$ 10,557**	$ 13,016
Total shareholders' equity	**$ 19,065**	$ 18,374
Debt to book capitalization	**36%**	41%

(1) Includes the current portion of the long-term debt.

10. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Weighted average common shares outstanding (thousands) – basic and diluted	**542,137**	540,819	**541,798**	540,557
Net earnings – basic and diluted	**$ 658**	$ 2,835	**$ 1,125**	$ 3,215
Net earnings per common share – basic and diluted	**$ 1.21**	$ 5.25	**$ 2.07**	$ 5.95

11. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	Sep 30, 2009		
Asset (liability)	**Loans and receivables at amortized cost**	**Held for trading at fair value**	**Other financial liabilities at amortized cost**
Cash and cash equivalents	**$ –**	**$ 14**	**$ –**
Accounts receivable	**1,006**	**–**	**–**
Other long-term assets	**–**	**149**	**–**
Accounts payable	**–**	**–**	**(272)**
Accrued liabilities	**–**	**–**	**(1,599)**
Other long-term liabilities	**–**	**(90)**	**(93)**
Long-term debt	**–**	**–**	**(10,557)**
	$ 1,006	**$ 73**	**$ (12,521)**

	Dec 31, 2008		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 27	$ –
Accounts receivable	1,059	–	–
Other long-term assets	–	2,119	–
Accounts payable	–	–	(383)
Accrued liabilities	–	–	(1,802)
Other long-term liabilities	–	–	(105)
Long-term debt (1)	–	–	(13,016)
	$ 1,059	$ 2,146	$ (15,306)

(1) Includes the current portion of the long-term debt.

The carrying value of the Company's financial instruments approximates their fair value, except for fixed-rate long-term debt as noted below:

	Sep 30, 2009		Dec 31, 2008	
	Carrying value	**Fair value**	Carrying value	Fair value
Fixed-rate long-term debt (1)	**$ 7,929**	**$ 8,567**	$ 8,943	$ 7,649

(1) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $47 million (2008 – $68 million) to reflect the fair value impact of hedge accounting.

Risk management

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

	Nine Months Ended Sep 30, 2009	Year Ended Dec 31, 2008
Asset (liability)	**Risk management mark-to-market**	Risk management mark-to-market
Balance – beginning of period	**$ 2,119**	$ (1,474)
Net cost of outstanding put options	**65**	297
Net change in fair value of outstanding derivative financial instruments attributable to:		
– Risk management activities	**(1,683)**	3,090
– Interest expense	**(17)**	60
– Foreign exchange	**(295)**	449
– Other comprehensive income	**(68)**	18
– Settlement of interest rate swaps and other	**4**	(20)
	125	2,420
Put premium financing obligations (1)	**(66)**	(301)
Balance – end of period	**59**	2,119
Less: current portion	**149**	1,851
	$ (90)	$ 268

(1) The Company has negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations have been reflected in the net risk management asset (liability).

Net (gains) losses from risk management activities were as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2009	Sep 30 2008	**Sep 30 2009**	Sep 30 2008
Net realized risk management (gain) loss	**$ (200)**	$ 791	**$ (1,131)**	$ 2,161
Net unrealized risk management loss (gain)	**274**	(2,506)	**1,683**	(983)
	$ 74	$ (1,715)	**$ 552**	$ 1,178

Financial risk factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production. At September 30, 2009, the Company had the following net derivative financial instruments outstanding to manage its commodity price exposures:

	Remaining term			Volume	Weighted average price			Index
Crude oil								
Crude oil price collars (1)	Oct 2009	–	Dec 2009	25,000 bbl/d	US$70.00	–	US$111.56	WTI
	Jan 2010	–	Jun 2010	100,000 bbl/d	US$60.00	–	US$90.13	WTI
	Jan 2010	–	Dec 2010	50,000 bbl/d	US$60.00	–	US$75.08	WTI
Crude oil puts	Oct 2009	–	Dec 2009	92,000 bbl/d			US$100.00	WTI

(1) Subsequent to September 30, 2009, the Company entered into 50,000 bbl/d of US$65.00 – US$105.49 WTI collars for the period January to September 2010.

At September 30, 2009, the net cost of outstanding put options to be settled during the fourth quarter of 2009 was US$61 million.

	Remaining term			Volume	Weighted average price			Index
Natural gas								
Natural gas price collars	Jan 2010	–	Dec 2010	220,000 GJ/d	C$6.00	–	C$8.00	AECO

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

There were no commodity derivative financial instruments designated as hedges at September 30, 2009.

In addition to the derivative financial instruments noted above, the Company entered into natural gas physical sales contracts for 400,000 GJ/d at an average fixed price of C$5.29 per GJ at AECO for the period October to December 2009.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At September 30, 2009, the Company had the following interest rate swap contracts outstanding:

	Remaining term			Amount ($ millions)	Fixed rate	Floating rate
Interest rate						
Swaps – fixed to floating	Oct 2009	–	Dec 2014	US$350	4.90%	LIBOR [1] + 0.38%
Swaps – floating to fixed	Oct 2009	–	Feb 2011	C$300	1.0680%	3 month CDOR [2]
	Oct 2009	–	Feb 2012	C$200	1.4475%	3 month CDOR [2]

(1) London Interbank Offered Rate

(2) Canadian Dealer Offered Rate

All interest rate related derivative financial instruments designated as hedges at September 30, 2009 were classified as fair value hedges.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At September 30, 2009, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Oct 2009	–	Aug 2016	US$250	1.116	6.00%	5.40%
	Oct 2009	–	May 2017	US$1,100	1.170	5.70%	5.10%
	Oct 2009	–	Mar 2038	US$550	1.170	6.25%	5.76%

In addition to the cross currency swap contracts noted above, at September 30, 2009, the Company had US$1,707 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

All cross currency swap and foreign currency forward derivative financial instruments designated as hedges at September 30, 2009 were classified as cash flow hedges.

Financial instrument sensitivities

As required by Canadian GAAP, the Company must provide certain quantitative sensitivities related to its financial instruments, which are prepared on a different basis than those sensitivities currently disclosed in the Company's other continuous disclosure documents. The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at September 30, 2009 resulting from changes in the specified variable, with all other variables held constant. These sensitivities are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$ (25)	$ –
Decrease WTI US$1.00/bbl	$ 25	$ –
Increase AECO C$0.10/mcf	$ (4)	$ –
Decrease AECO C$0.10/mcf	$ 4	$ –
Interest rate risk		
Increase interest rate 1%	$ (20)	$ 8
Decrease interest rate 1%	$ 20	$ (9)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (30)	$ –
Decrease exchange rate by US$0.01	$ 30	$ –

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At September 30, 2009, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At September 30, 2009, the Company had net risk management assets of $108 million with specific counterparties related to derivative financial instruments (December 31, 2008 – $2,119 million).

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, and access to debt capital markets, to meet obligations as they become due. Due to fluctuations in the timing of the receipt and/or disbursement of operating cash flows, the Company believes it has adequate bank credit facilities to provide liquidity.

The maturity dates for financial liabilities are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 272	$ –	$ –	$ –
Accrued liabilities	$ 1,599	$ –	$ –	$ –
Risk management	$ –	$ 38	$ 21	$ 31
Other long-term liabilities	$ 91	$ 2	$ –	$ –
Long-term debt (1)	$ –	$ 829	$ 1,204	$ 5,922

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $2,628 million of revolving bank credit facilities due to the extendable nature of the facilities.

12. COMMITMENTS

As at September 30, 2009, the Company had committed to certain payments as follows:

	Remaining 2009	2010	2011	2012	2013	Thereafter
Product transportation and pipeline	$ 59	$ 194	$ 157	$ 132	$ 124	$ 1,169
Offshore equipment operating leases	$ 51	$ 145	$ 126	$ 102	$ 103	$ 348
Offshore drilling	$ 42	$ 50	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 3	$ 10	$ 16	$ 17	$ 26	$ 5,739
Office leases	$ 6	$ 28	$ 22	$ 3	$ 2	$ 2
Other	$ 107	$ 189	$ 16	$ 9	$ 7	$ 18

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2009 – 2013 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

13. SEGMENTED INFORMATION

	Conventional Crude Oil and Natural Gas															
	North America				North Sea				Offshore West Africa				Total Conventional			
(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Segmented revenue	**1,906**	3,883	**5,753**	11,380	**220**	462	**666**	1,507	**223**	234	**606**	758	**2,349**	4,579	**7,025**	13,645
Less: royalties	**(196)**	(561)	**(581)**	(1,617)	**-**	(1)	**(1)**	(3)	**(29)**	(50)	**(59)**	(129)	**(225)**	(612)	**(641)**	(1,749)
Segmented revenue, net of royalties	**1,710**	3,322	**5,172**	9,763	**220**	461	**665**	1,504	**194**	184	**547**	629	**2,124**	3,967	**6,384**	11,896
Segmented expenses																
Production	**436**	498	**1,357**	1,424	**90**	123	**273**	340	**43**	15	**116**	61	**569**	636	**1,746**	1,825
Transportation and blending	**237**	483	**867**	1,674	**1**	3	**6**	8	**1**	1	**1**	1	**239**	487	**874**	1,683
Depletion, depreciation and amortization	**512**	556	**1,573**	1,684	**53**	75	**196**	233	**45**	26	**133**	94	**610**	657	**1,902**	2,011
Asset retirement obligation accretion	**10**	12	**30**	32	**6**	6	**19**	19	**1**	-	**3**	1	**17**	18	**52**	52
Realized risk management activities	**(130)**	791	**(802)**	2,162	**(70)**	-	**(329)**	(1)	**-**	-	**-**	-	**(200)**	791	**(1,131)**	2,161
Total segmented expenses	**1,065**	2,340	**3,025**	6,976	**80**	207	**165**	599	**90**	42	**253**	157	**1,235**	2,589	**3,443**	7,732
Segmented earnings before the following	**645**	982	**2,147**	2,787	**140**	254	**500**	905	**104**	142	**294**	472	**889**	1,378	**2,941**	4,164
Non-segmented expenses																
Administration																
Stock-based compensation expense (recovery)																
Interest, net																
Unrealized risk management activities																
Foreign exchange (gain) loss																
Total non-segmented expenses																
Earnings before taxes																
Taxes other than income tax																
Current income tax expense																
Future income tax expense (recovery)																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2009	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008	**2009**	2008
Segmented revenue	**469**	-	**761**	-	**18**	20	**54**	60	**(13)**	(16)	**(81)**	(43)	**2,823**	4,583	**7,759**	13,662
Less: royalties	**(15)**	-	**(18)**	-	**-**	-	**-**	-	**-**	-	**8**	-	**(240)**	(612)	**(651)**	(1,749)
Segmented revenue, net of royalties	**454**	-	**743**	-	**18**	20	**54**	60	**(13)**	(16)	**(73)**	(43)	**2,583**	3,971	**7,108**	11,913
Segmented expenses																
Production	**242**	-	**424**	-	**4**	6	**14**	19	**(2)**	(3)	**(16)**	(8)	**813**	639	**2,168**	1,836
Transportation and blending	**13**	-	**27**	-	**-**	-	**-**	-	**(11)**	(15)	**(34)**	(37)	**241**	472	**867**	1,646
Depletion, depreciation and amortization	**66**	-	**104**	-	**2**	2	**6**	6	**(5)**	-	**(29)**	-	**673**	659	**1,983**	2,017
Asset retirement obligation accretion	**7**	-	**15**	-	**-**	-	**-**	-	**-**	-	**-**	-	**24**	18	**67**	52
Realized risk management activities	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(200)**	791	**(1,131)**	2,161
Total segmented expenses	**328**	-	**570**	-	**6**	8	**20**	25	**(18)**	(18)	**(79)**	(45)	**1,551**	2,579	**3,954**	7,712
Segmented earnings before the following	**126**	-	**173**	-	**12**	12	**34**	35	**5**	2	**6**	2	**1,032**	1,392	**3,154**	4,201
Non-segmented expenses																
Administration													**38**	46	**132**	134
Stock-based compensation expense (recovery)													**172**	(308)	**268**	151
Interest, net													**118**	25	**299**	105
Unrealized risk management activities													**274**	(2,506)	**1,683**	(983)
Foreign exchange (gain) loss													**(424)**	73	**(547)**	156
Total non-segmented expenses													**178**	(2,670)	**1,835**	(437)
Earnings before taxes													**854**	4,062	**1,319**	4,638
Taxes other than income tax													**23**	45	**74**	156
Current income tax expense													**90**	171	**294**	477
Future income tax expense (recovery)													**83**	1,011	**(174)**	790
Net earnings													**658**	2,835	**1,125**	3,215

Net additions to property, plant and equipment

	Nine Months Ended					
	Sep 30, 2009			Sep 30, 2008		
	Net Expenditures	**Non Cash/Fair Value Changes (1)**	**Capitalized Costs**	Net Expenditures	Non Cash/Fair Value Changes (1)	Capitalized Costs
North America	**$ 1,227**	**$ (4)**	**$ 1,223**	$ 1,858	$ 18	$ 1,876
North Sea	**120**	**–**	**120**	202	–	202
Offshore West Africa	**464**	**51**	**515**	453	(3)	450
Other	**1**	**–**	**1**	1	–	1
Oil Sands Mining and Upgrading (2)	**446**	**275**	**721**	3,068	–	3,068
Midstream	**5**	**–**	**5**	6	–	6
Head office	**9**	**–**	**9**	13	–	13
	$ 2,272	**$ 322**	**$ 2,594**	$ 5,601	$ 15	$ 5,616

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for the Oil Sands Mining and Upgrading assets also include capitalized interest, stock-based compensation, and the impact of inter-segment eliminations.

	Property, plant and equipment		Total assets	
	Sep 30 2009	Dec 31 2008	**Sep 30 2009**	Dec 31 2008
Segmented assets				
North America	**$ 21,815**	$ 22,151	**$ 22,937**	$ 24,875
North Sea	**1,717**	2,048	**1,884**	2,638
Offshore West Africa	**1,980**	1,894	**2,105**	2,013
Other	**27**	26	**67**	64
Oil Sands Mining and Upgrading	**13,190**	12,573	**13,498**	12,677
Midstream	**205**	206	**300**	315
Head office	**62**	68	**62**	68
	$ 38,996	$ 38,966	**$ 40,853**	$ 42,650

Capitalized interest

The Company capitalizes construction period interest to Oil Sands Mining and Upgrading based on costs incurred and the Company's cost of borrowing. Interest capitalization on a particular development phase ceases once construction is substantially complete. For the nine months ended September 30, 2009, pre-tax interest of $98 million was capitalized to Oil Sands Mining and Upgrading (September 30, 2008 – $346 million).

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated September 2007. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended September 30, 2009:	
Interest coverage (times)	
Net earnings [(1)]	7.5x
Cash flow from operations [(2)]	11.9x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

(2) Cash flow from operations plus current income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

CORPORATE INFORMATION

Officers

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Chairman of the Board

N. Murray Edwards*
Vice-Chairman of the Board

John G. Langille*
Vice-Chairman of the Board

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President & Chief Operating Officer

Douglas A. Proll*
Chief Financial Officer &
Senior Vice-President, Finance

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Senior Vice-President, Marketing

Réal J.H. Doucet*
Senior Vice-President, Oil Sands

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Senior Vice-President, International & Thermal

Allen M. Knight*
Senior Vice-President, International & Corporate Development

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Senior Vice-President, Operations

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Senior Vice-President, Exploitation

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Senior Vice-President, Exploration

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Stakeholder & Environmental Affairs

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Vice-President, Human Resources, Horizon

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Vice-President, Production - Central

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Peter J. Janson
Vice-President, Engineering Integration

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Vice-President, Mining

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Vice-President, Development Operations

Reno Laseur
Vice-President, Upgrading & Utilities

León Miura
Vice-President, Horizon Major Projects

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Vice-President, Human Resources

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Vice-President, Bitumen Production

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Vice-President, Project Control

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Vice-President, Field Operations

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Vice-President, Information & Corporate Services

Domenic Torriero
Vice-President, Exploration - Central

Grant M. Williams
Vice-President, Exploration - East

Daryl G. Youck
Vice-President, Exploitation - East

Lynn M. Zeidler
Vice-President, Facilities & Services

Bruce E. McGrath
Corporate Secretary

*Management Committee

Stock Listing

Toronto Stock Exchange
Trading Symbol – CNQ

New York Stock Exchange
Trading Symbol – CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Board of Directors

Catherine M. Best, FCA

N. Murray Edwards

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Ambassador Gordon D. Giffin

John G. Langille

Steve W. Laut

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James S. Palmer, C.M., A.O.E., Q.C.

Eldon R. Smith, O.C., M.D.

David A. Tuer

International Operations

CNR International (U.K.) Limited

Aberdeen, Scotland

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W. David R. Bell
Vice-President, Exploration, International

Barry Duncan
Vice President, Finance, International

Darren Fichter,
Vice President, Exploitation, International

David M. Haywood
Vice-President, Operations, International

David B. Whitehouse
Vice-President, Production Operations

Investor Relations

Telephone: (403) 514-7777

Facsimile: (403) 514-7888

Email: ir@cnrl.com

Website: www.cnrl.com

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C A N A D I A N   N A T U R A L   R E S O U R C E S   L I M I T E D
2500, 855 - 2 Street S.W., Calgary, Alberta T2P 4J8
Telephone: (403) 517-6700   Facsimile: (403) 517-7350
Email: ir@cnrl.com
Website: www.cnrl.com

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